**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

Midcontinent Independent System Operator, Inc.,	)	
	)	
Petitioner,	)	
	)	
v.	)	No. 23-1284__
	)	
Federal Energy Regulatory Commission,	)	
	)	
Respondent.	)	

PETITION FOR REVIEW

Pursuant to section 313(b) of the Federal Power Act, 16 U.S.C. § 825*l*(b), Rule 15(a) of the Federal Rules of Appellate Procedure, and Rule 15 of the Circuit Rules of this Court, the Midcontinent Independent System Operator, Inc. ("MISO") petitions this Court for review of the following orders issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket Nos. RM22-14-000 and RM22-14-001:

- *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, Docket No. RM22-14-000, 184 FERC ¶ 61,054 (July 28, 2023) ("Order No. 2023"); and

- *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration, Docket No. RM22-14-001, 184 FERC ¶ 62,163 (2023) (Sept. 28, 2023) ("Rehearing Denial Notice").

A copy of Order No. 2023 is attached as Exhibit A to this petition. A copy of the Rehearing Denial Notice is attached as Exhibit B to this petition.

The agency proceeding at issue concerns revisions to the Commission's *pro forma* Large Generator Interconnection Procedures, *pro forma* Small Generator Interconnection Procedures, *pro forma* Large Generator Interconnection Agreement, and *pro forma* Small Generator Interconnection Agreement. MISO seeks review of the underlying orders on the grounds that the Commission's rulings are arbitrary, capricious, an abuse of discretion, and otherwise are not in accordance with law within the meaning of the Administrative Procedure Act, 5 U.S.C. §§ 701–706, and are not supported by substantial evidence as required by the Federal Power Act, 16 U.S.C. § 825*l*(b).

MISO timely requested rehearing of Order No. 2023 on August 28, 2023. *See* Ex. B at 1 ("Rehearing has been timely requested of the Commission's order issued on July 28, 2023, in this proceeding."). The Rehearing Denial Notice states:

> In the absence of Commission action on a request for rehearing within 30 days from the date it is filed, the request for rehearing may be deemed to have been denied. 16 U.S.C. § 825*l*(a); 18 C.F.R. § 385.713 (2022); *Allegheny Def. Project v. FERC*, 964 F.3d 1 (D.C. Cir. 2020) (en banc). *Id*.

The Rehearing Denial Notice further provides that the rehearing requests "will be addressed in a future order to be issued consistent with the requirements of [16 U.S.C. § 825*l*(a)]." *Id*. No "future order" has yet been issued.

In *Allegheny Defense Project v. Federal Energy Regulatory Commission*, the Court concluded that as "a matter of plain statutory text and structure, the Commission lacks [the] authority" to issue tolling orders "for the sole purposes of preventing rehearing from being deemed denied by its inaction and the statutory right to judicial review attaching." *Allegheny Def. Project v. FERC*, 964 F.3d 1, 11 (D.C. Cir. 2020) (en banc) ("*Allegheny Defense*"). Consistent with *Allegheny Defense* and Federal Power Act section 313(a), 16 U.S.C. § 825*l*(a), MISO's request for rehearing is deemed denied and is ripe for review by this Court.

Venue is proper in this Court pursuant to Federal Power Act section 313(b), 16 U.S.C. § 825*l*(b).

Respectfully submitted,

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Dated: October 10, 2023

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Midcontinent Independent System Operator, Inc.,	)	
Petitioner,	)	
v.	)	No. 23-___
Federal Energy Regulatory Commission,	)	
Respondent.	)	

CORPORATE DISCLOSURE STATEMENT OF
THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and Rule 26.1 of the Circuit Rules of this Court, Midcontinent Independent System Operator, Inc. ("MISO") hereby submits the following corporate disclosure statement:

MISO is a non-stock, not-for-profit corporation organized under the laws of the State of Delaware with its principal place of business in Carmel, Indiana. MISO has no parent corporation, and because MISO is a non-profit corporation that does not issue stock, no publicly held corporation owns 10% or more stock in MISO. Circuit Rule 26.1(b) requires a statement that identifies the represented entity's general nature and purpose, insofar as is relevant to the petition for review in this proceeding. As is relevant here, MISO is an independent regional transmission

system operator authorized by the Federal Energy Regulatory Commission to administer an open access transmission tariff, ensure reliable operation of, and equal access to, high-voltage power lines in 15 U.S. states and the Canadian province of Manitoba, and operates one of the world's largest wholesale electricity markets with more than $29 billion in annual gross market energy transactions.

Pursuant to Circuit Rule 26.1(b) of this Court, MISO identifies the following law firms whose partners or associates have appeared in this case or are expected to appear on behalf of MISO:

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Dated: October 10, 2023

CERTIFICATE OF SERVICE

Pursuant to F.R.A.P. 15(c) and 25(d), I hereby certify that I caused the foregoing Petition for Review to be served upon the Secretary of the Federal Energy Regulatory Commission and the Office of the Solicitor of the Federal Energy Regulatory Commission at the following addresses:

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First St., NE
Washington, DC 20426

Robert H. Solomon, Solicitor
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Pursuant to 18 C.F.R. § 385.2012 and 28 U.S.C. § 2112(a), I further certify that I will mail a date-stamped copy of this petition to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426. Pursuant to F.R.A.P. 15(c), I further certify that I caused the foregoing document to be served by e-mail on all the parties on the Commission's service list for Docket No. RM22-14, attached hereto.

Respectfully submitted,

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Dated: October 10, 2023

Exhibit A

Improvements to Generator Interconnection

Procedures and Agreements

Order No. 2023

Docket No. RM22-14-000

184 FERC ¶ 61,054

(July 28, 2023)

184 FERC ¶ 61,054
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM22-14-000; Order No. 2023]

Improvements to Generator Interconnection Procedures and Agreements

(Issued July 28, 2023)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission or FERC) is adopting reforms to its *pro forma* Large Generator Interconnection Procedures, *pro forma* Small Generator Interconnection Procedures, *pro forma* Large Generator Interconnection Agreement, and *pro forma* Small Generator Interconnection Agreement to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. The reforms are intended to ensure that the generator interconnection process is just, reasonable, and not unduly discriminatory or preferential.

EFFECTIVE DATE: This final rule will become effective **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

184 FERC ¶ 61,054
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Willie L. Phillips, Acting Chairman;
James P. Danly, Allison Clements,
and Mark C. Christie.

Improvements to Generator Interconnection Procedures and Agreements — Docket No. RM22-14-000

ORDER NO. 2023

FINAL RULE

(Issued July 28, 2023)

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I. **<u>Introduction</u>**

1. This final rule requires all public utility transmission providers to adopt revised *pro forma* Large Generator Interconnection Procedures (LGIP), *pro forma* Small Generator Interconnection Procedures (SGIP), *pro forma* Large Generator Interconnection Agreements (LGIA), and *pro forma* Small Generator Interconnection

Agreements (SGIA).[1] These revisions will ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and will prevent undue discrimination.

2. Twenty years ago the Commission issued Order No. 2003, in which the Commission required all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have on file standard procedures and a standard agreement for interconnecting generating facilities larger than 20 megawatts (MW) (called the *pro forma* LGIP and the *pro forma* LGIA).[2] The Commission stated its expectation that the changes would prevent undue discrimination, preserve reliability, increase energy supply, and lower wholesale prices for customers by

[1] Section 201(e) of the Federal Power Act (FPA) defines "public utility" to mean "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter." 16 U.S.C. 824(e). A non-public utility that seeks voluntary compliance with the reciprocity condition of a tariff may satisfy that condition by filing a tariff, which includes the *pro forma* LGIP, the *pro forma* SGIP, the *pro forma* LGIA, and the *pro forma* SGIA. *See Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at PP 1, 616 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 5, 2004), 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 19, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (July 18, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (*NARUC v. FERC*). As stated in the *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA, transmission provider "shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the [Transmission Provider's Tariff]. The term . . . should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider." *Pro forma* LGIP section 1; *pro forma* LGIA art. 1; *pro forma* SGIP attach. 1; *pro forma* SGIA attach. 1.

[2] Order No. 2003, 104 FERC ¶ 61,103 at P 2.

increasing the amount and variety of new generation that would compete in the wholesale electricity market.[3] The Commission further stated that the standard procedures would facilitate market entry for generation competitors by reducing interconnection costs and time.[4] In Order No. 2006, the Commission adopted standard procedures and a standard agreement for interconnecting generating facilities no larger than 20 MW (called the *pro forma* SGIP and the *pro forma* SGIA), citing the same purposes outlined in Order No. 2003.[5]

3. The electricity sector has transformed significantly since the issuance of Order Nos. 2003 and 2006. The growth of new resources seeking to interconnect to the transmission system and the differing characteristics of those resources have created new challenges for the generator interconnection process. These new challenges are creating large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system, increasing costs for consumers. Backlogs in the generator interconnection process, in turn, can create reliability issues as needed new generating facilities are unable to come online in an efficient and timely manner. While

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[3] *Id.* P 1.

[4] *Id.* P 12.

[5] *Standardization of Small Generator Interconnection Agreements & Procs.*, Order No. 2006, 111 FERC ¶ 61,220, at PP 15, 35-36, *order on reh'g*, Order No. 2006-A, 70 FR 71760 (Dec. 30, 2005), 113 FERC ¶ 61,195 (2005), *order granting clarification*, Order No. 2006-B, 71 FR 42587 (July 27, 2006), 116 FERC ¶ 61,046 (2006).

the Commission recognized these issues and sought to address them in Order No. 845,[6] it is clear that further action is needed. Therefore, we believe that it is necessary to reform the Commission's standard interconnection procedures and agreements to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, thereby ensuring that rates, terms, and conditions for Commission-jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.

4. Accordingly, we adopt reforms to the Commission's *pro forma* LGIP and *pro forma* LGIA. Specifically, as explained in detail in this final rule, we adopt reforms to: (1) implement a first-ready, first-served cluster study process;[7] (2) increase the speed of interconnection queue processing; and (3) incorporate technological advancements into the interconnection process.

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[6] *See Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 83 FR 21342 (May 9, 2018), 163 FERC ¶ 61,043, at P 24 (2018), *order on reh'g*, Order No. 845-A, 84 FR 8156 (Mar. 6, 2019) 166 FERC ¶ 61,137, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

[7] A first-ready, first-served cluster study process improves efficiency in the interconnection study process by including the following elements: increased access to information prior to entering the queue; a mechanism to study interconnection requests in groups where all interconnection requests in the group are equally queued and of equal study priority; and increased financial commitments and readiness requirements to enter and proceed through the queue. In contrast, the existing first-come, first-served serial study process in the *pro forma* LGIA and LGIP provides limited information to interconnection customers prior to entering the queue, assigns interconnection requests an individual queue position based solely on the date of entry into the queue, and contains limited financial and readiness requirements.

5. First, in order to implement a first-ready, first-served cluster study process, this final rule requires: (1) transmission providers to publicly post available information pertaining to generator interconnection; (2) transmission providers to use cluster studies as the interconnection study method; (3) transmission providers to allocate cluster study costs on a pro rata and per capita basis; (4) transmission providers to allocate network upgrade costs based on a proportional impact method; (5) interconnection customers to pay study and commercial readiness deposits as part of the cluster study process; (6) interconnection customers to demonstrate site control at the time of submission of the interconnection request; and (7) transmission providers to impose withdrawal penalties on interconnection customers for withdrawing from the interconnection queue, with certain exceptions. We also require transmission providers to adopt a transition process to move from the existing serial interconnection process to the new cluster study process.

6. Second, in order to increase the speed of interconnection queue processing, this final rule: (1) eliminates the reasonable efforts standard for conducting interconnection studies and imposes a financial penalty on transmission providers that fail to meet interconnection study deadlines; and (2) establishes an affected system study process and associated *pro forma* affected system agreements.

7. Third, in order to incorporate technological advancements into the interconnection process, this final rule requires transmission providers to: (1) allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request; (2) evaluate the proposed addition of a generating facility at the same point of interconnection prior to deeming such an addition

a material modification if the addition does not change the originally requested interconnection service level; (3) allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA; (4) use operating assumptions in interconnection studies that reflect the proposed charging behavior of an electric storage resource; and (5) evaluate the list of alternative transmission technologies enumerated in this final rule during the generator interconnection study process. This final rule also requires interconnection customers requesting to interconnect a non-synchronous generating facility to: (1) provide the transmission provider with the models needed for accurate interconnection studies; and (2) have the ability to maintain power production at pre-disturbance levels and provide dynamic reactive power to maintain system voltage during transmission system disturbances and within physical limits. Finally, this final rule requires that all newly interconnecting large generating facilities provide ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis.

8. We also adopt reforms to the *pro forma* SGIP and *pro forma* SGIA. Specifically, as explained in detail in this final rule, for small generating facilities we propose reforms to incorporate the enumerated alternative transmission technologies into the interconnection process, and to provide modeling and ride through requirements for non-synchronous generating facilities.

9. Many of the reforms adopted in this final rule track the Notice of Proposed Rulemaking's[8] (NOPR) proposed reforms closely. However, as discussed more fully below, we have revised aspects of the reforms pertaining to the cluster study process, allocation of cluster study and network upgrade costs, increased financial commitments and readiness requirements, financial penalties for delayed interconnection studies, the affected system study process, *pro forma* affected system agreements, the material modification process, operating assumptions for interconnection studies, incorporating the enumerated alternative transmission technologies, and ride through requirements. Additionally, as discussed more fully below, we decline to adopt the NOPR proposals pertaining to informational interconnection studies, shared network upgrades, the optional resource solicitation study, and the alternative transmission technologies annual report.

10. We recognize that transmission providers have undertaken efforts to address interconnection queue management issues. This final rule is not intended to divert or slow the potential progress represented by those efforts, and we encourage transmission providers to continue to innovate to remedy their identified interconnection queue management issues. We note that the compliance obligations that result from this final rule will be evaluated in light of the independent entity variation standard for regional

[8] *Improvements to Generator Interconnection Procs. & Agreements*, 87 FR 39934 (July 5, 2022), 179 FERC ¶ 61,194 (2022) (NOPR).

transmission organizations (RTO) and independent system operators (ISO) and the consistent with or superior to standard for non-RTO/ISO transmission providers.[9]

A. Historical Framework: Order Nos. 2003, 2006, and 845

11. In Order No. 2003, the Commission recognized a need for a standard set of interconnection procedures for transmission providers and a single, uniformly applicable interconnection agreement for large generating facilities.[10] The Commission noted that generator interconnection is a "critical component of open access transmission service and thus is subject to the requirement that utilities offer comparable service under the [*pro forma* open access transmission tariff (tariff)]."[11] The Commission found that it was appropriate to establish a standard set of generator interconnection procedures to "minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[12] To this end, the Commission adopted the *pro forma* LGIP and *pro forma* LGIA and

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[9] Order No. 2003, 104 FERC ¶ 61,103 at P 26; *see infra* Section IV.

[10] Order No. 2003, 104 FERC ¶ 61,103 at P 11. Large generating facilities are defined to mean "a Generating Facility having a Generating Facility Capacity of more than 20 MW." *Pro forma* LGIP section 1.

[11] Order No. 2003, 104 FERC ¶ 61,103 at P 9 (citing *Tenn. Power Co.*, 90 FERC ¶ 61,238 (2000)).

[12] *Id.* P 11.

amended its regulations to require all transmission providers to incorporate these standard procedures and agreement into their tariffs.[13]

12. To initiate the generator interconnection process set forth in the Commission's *pro forma* LGIP,[14] the interconnection customer submits an interconnection request for its proposed generating facility that includes preliminary documentation of the site of the proposed generating facility, certain technical information about the proposed generating facility, and the expected commercial operation date of the proposed generating facility, along with a refundable deposit of $10,000.[15] After the transmission provider determines that the interconnection request is complete, the interconnection request enters the transmission provider's interconnection queue with other pending interconnection requests and is assigned a queue position based on the time and date of its receipt.[16] The queue position determines the order in which the transmission provider studies the interconnection requests in its interconnection queue.[17]

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[13] 18 CFR 35.28(f)(1) (2022).

[14] While we provide a broad description of the process in the Commission's *pro forma* LGIP as background here, we recognize that many transmission providers have adopted (and the Commission has accepted) variations to many of the terms in the Commission's *pro forma* LGIP and *pro forma* LGIA. Consequently, some or many of the details of a particular transmission provider's generator interconnection procedures may vary considerably from the broad description provided here.

[15] Order No. 2003, 104 FERC ¶ 61,103 at P 35; *pro forma* LGIP sections 3.1, 3.4.

[16] *Pro forma* LGIP section 4.1.

[17] *Id.*

13. Transmission providers must schedule a scoping meeting with the interconnection customer to discuss possible points of interconnection for the proposed generating facility and exchange technical information, which is followed by a series of interconnection studies to evaluate the proposed interconnection in detail.[18] Transmission providers study interconnection requests in three phases: (1) the interconnection feasibility study (feasibility study);[19] (2) the interconnection system impact study (system impact study);[20] and (3) the interconnection facilities study (facilities study).[21] These studies contain the power flow, short circuit, and stability analyses necessary to: (1) identify any adverse

[18] Order No. 2003, 104 FERC ¶ 61,103 at P 36; *pro forma* LGIP sections 3.4.4, 6-8.

[19] The *pro forma* LGIP defines a feasibility study as "a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System." The scope of a feasibility study is described in section 6 of the *pro forma* LGIP. *Pro forma* LGIP sections 1, 6.

[20] The *pro forma* LGIP defines a system impact study as "an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System." In particular, a system impact study identifies and details "the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the [feasibility study], or to study potential impacts, including but not limited to those identified in the Scoping Meeting." *Id.* section 1.

[21] The *pro forma* LGIP defines a facilities study as "a study conducted by the Transmission Provider or a third-party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the [system impact study]), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System." The scope of a facilities study is described in section 8 of the *pro forma* LGIP. *Id.* sections 1, 8.

impacts on the transmission providers' transmission system or any affected systems;[22] (2) determine the interconnection facilities and network upgrades[23] needed to reliably interconnect the generating facility; and (3) estimate the interconnection customer's cost responsibility for these facilities.[24] The *pro forma* LGIP requires that transmission providers use reasonable efforts to complete: (1) feasibility studies within 45 calendar days; (2) system impact studies within 90 calendar days; and (3) facilities studies within 90 or 180 calendar days, depending on the interconnection customer's requested accuracy margin.[25]

14. At the completion of the facilities study, the *pro forma* LGIP requires the transmission provider to issue a report on the best estimate of the costs to effectuate the requested interconnection and provide a draft generator interconnection agreement to the

[22] The *pro forma* LGIP defines an affected system as an electric system other than the transmission provider's transmission system that may be affected by the proposed interconnection. *Id*. section 1; *pro forma* LGIA art. 1.

[23] For purposes of this final rule, unless otherwise noted, "network upgrades" refer to interconnection-related network upgrades. More specifically, the *pro forma* LGIP and *pro forma* LGIA provide that, "Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." *Pro forma* LGIP section 1; *pro forma* LGIA art. 1.

[24] Order No. 2003, 104 FERC ¶ 61,103 at PP 35-37; *pro forma* LGIP sections 6–8. The interconnection customer is responsible for the actual costs of interconnection studies and any necessary restudies. *Pro forma* LGIP section 13.3.

[25] *Pro forma* LGIP sections 6.3, 7.4, 8.3.

interconnection customer.[26] If the interconnection customer wishes to proceed, after negotiations, the interconnection customer enters into a generator interconnection agreement with the transmission provider or, in specific circumstances, requests that the transmission provider file the agreement with the Commission unexecuted.[27] The transmission provider is responsible for the construction of all network upgrades, but, as further discussed below, the interconnection customer has the option to build these facilities in certain circumstances.[28]

15. Similar to Order No. 2003, in Order No. 2006, the Commission recognized the need for standardized interconnection procedures and agreements for small generating facilities with a capacity of 20 MW or less.[29] In addition to establishing a *pro forma* interconnection study process for small generating facilities similar to the process for

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[26] Order No. 2003, 104 FERC ¶ 61,103 at P 38. Section 11.1 of the *pro forma* LGIP requires the transmission provider to tender a draft LGIA to the interconnection customer "in the form of Transmission Provider's FERC-approved standard form LGIA."

[27] If the transmission provider and interconnection customer execute an LGIA that conforms to the transmission provider's Commission-approved standard form LGIA, the agreement does not need to be filed with the Commission (if the transmission provider has such a standard form LGIA on file and submits an Electronic Quarterly Report). Alternatively, the transmission provider must file an LGIA with the Commission for review and approval if: (1) the interconnection customer determines that negotiations with the transmission provider over the terms of an LGIA are at an impasse and requests submission of the unexecuted LGIA with the Commission; or (2) the LGIA does not conform to the transmission provider's Commission-approved standard form LGIA. *See* Order No. 2003-A, 106 FERC ¶ 61,220 at P 201; *pro forma* LGIP sections 11.2-11.3.

[28] Order No. 2003, 104 FERC ¶ 61,103 at PP 351-354; *pro forma* LGIA art. 5.1.3.

[29] Order No. 2006, 111 FERC ¶ 61,220 at P 36.

large generating facilities established in Order No. 2003, the Commission included: (1) a "fast track process"[30] that uses technical screens to evaluate a certified small generating facility no larger than 2 MW; and (2) a "10 [kilowatt (kW)] inverter process"[31] that uses the same technical screens to evaluate a certified inverter-based small generating facility no larger than 10 kW.[32] The Commission later issued Order No. 792,[33] in which the Commission revised the *pro forma* SGIP and *pro forma* SGIA to provide for interconnection customers to receive point of interconnection information in advance of submitting an interconnection request, increase the threshold for participation in the fast track process to five MW, and to specifically include electric storage devices.[34]

16. In response to concerns voiced to the Commission about interconnection queue management, in 2007, the Commission held a technical conference,[35] and later issued an order[36] addressing interconnection queue issues in RTOs/ISOs. In the order, the

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[30] *Pro forma* SGIP section 2.1.

[31] *Id.* attach. 5.

[32] Order No. 2006, 111 FERC ¶ 61,220 at PP 36, 38-39.

[33] *Small Generator Interconnection Agreements & Procs.*, Order No. 792, 78 FR 73240 (Dec. 5, 2013), 145 FERC ¶ 61,159 (2013), *clarifying*, Order No. 792-A, 146 FERC ¶ 61,214 (2014).

[34] *See* Order No. 792, 145 FERC ¶ 61,159 at P 1.

[35] *Interconnection Queuing Practices*, Notice of Technical Conference, Docket No. AD08-2-000 (issued Nov. 2, 2007).

[36] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252 (2008) (2008 Technical Conference Order).

Commission noted that some transmission providers were not processing their interconnection queues within the timelines established in the *pro forma* LGIP, and in certain cases, were greatly exceeding them.[37] The Commission stated that, although it "may need to [impose solutions] if the RTOs and ISOs do not act themselves," each RTO/ISO would have an opportunity to work with its stakeholders to develop its own solutions.[38] As further discussed below, following the order, multiple RTOs/ISOs submitted queue reform proposals to the Commission, some of which moved away from a so-called "first-come, first-served" approach (whereby interconnection requests are processed in the order they are received) to a so-called "first-ready, first-served" approach (whereby interconnection requests are processed based on when interconnection customers meet certain project development milestones).[39] The reason for this move was to allow interconnection customers with interconnection requests for generating facilities more likely to achieve commercial operation to move faster instead of being delayed by interconnection requests that were higher in the interconnection queue but making limited or no progress towards commercial operation and creating unreasonable queue delays.

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[37] *Id.* P 3.

[38] *Id.* P 8.

[39] *See, e.g.*, *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114 (2009); *Midwest Indep. Transmission Sys. Operator, Inc.*, 124 FERC ¶ 61,183 (2008); *Cal. Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,292 (2008).

17. In 2018, the Commission issued Order No. 845, in which the Commission made the most comprehensive revisions to the *pro forma* LGIP and *pro forma* LGIA since their adoption in Order No. 2003. In Order No. 845, the Commission concluded that reforms to the *pro forma* LGIP and *pro forma* LGIA were needed to mitigate concerns regarding systemic inefficiencies, remedy discriminatory practices, and address recent developments, including changes in the resource mix and emergence of new technologies.[40] The Commission therefore adopted reforms designed to improve certainty for interconnection customers, promote more informed interconnection decisions, and enhance the generator interconnection process.[41]

B. Regional Transmission Planning and Cost Allocation and Generator Interconnection Advance Notice of Proposed Rulemaking

18. On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR) in Docket No. RM21-17-000, presenting potential reforms to the Commission's requirements governing the regional transmission planning and cost allocation and generator interconnection processes.[42] Specific to the generator interconnection process, the Commission sought comment on whether and which reforms may be necessary to ensure a more purposeful integration of the generator

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[40] Order No. 845, 163 FERC ¶ 61,043 at P 7.

[41] *Id.* P 2.

[42] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 86 FR 40266 (July 15, 2021), 176 FERC ¶ 61,024 (2021) (ANOPR).

interconnection process with the regional transmission planning and cost allocation processes, establish a faster and more efficient interconnection queueing process, and promote a more efficient and cost-effective allocation of network upgrade costs.[43] For instance, the Commission noted that the cost of network upgrades can depend largely on both the timing of when the interconnection customer enters the interconnection queue and where the interconnection customer proposes to interconnect its generating facility. Therefore, the Commission noted, interconnection customers may submit multiple interconnection requests in an effort to determine the most favorable point of interconnection[44] that minimizes their network upgrade costs.[45] The Commission stated that this practice, in turn, may lead to late-stage withdrawals of the excess interconnection requests, which can then impede the transmission provider's ability to process its interconnection queue in an efficient manner. As a result, the Commission stated that it may be time to consider reforms to the generator interconnection process that would make it more efficient and ensure that generating facilities that are more "ready" than others are not unduly delayed in the interconnection queue.

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[43] *Id.* P 5.

[44] The *pro forma* LGIP defines point of interconnection as "the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System." *Pro forma* LGIP section 1.

[45] ANOPR, 176 FERC ¶ 61,024 at P 41.

19. On April 21, 2022, the Commission issued a Notice of Proposed Rulemaking (Transmission Planning and Cost Allocation NOPR) proposing reforms to its existing regional transmission planning and cost allocation requirements in the same proceeding as it issued the ANOPR.[46] While the Transmission Planning and Cost Allocation NOPR did not address many of the concerns raised by the Commission in the ANOPR with respect to the generator interconnection queue process, the Commission noted in the Transmission Planning and Cost Allocation NOPR that it would continue to review the record and that it expected to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to that topic.[47] The Commission took that next step with the reforms proposed in the NOPR in this proceeding, many of which we adopt in this final rule.

C. <u>Notice of Proposed Rulemaking</u>

20. On June 16, 2022, the Commission issued the NOPR, proposing reforms focused on improving aspects of the *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA. The Commission also sought comment on, but did not propose, tariff revisions on other issues.

21. First, the Commission proposed reforms focused on improving interconnection processes to ensure interconnection customers can proceed in an efficient and timely

[46] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028 (2022).

[47] *Id.* P 10.

manner.[48] Among those, the Commission proposed to: (1) require transmission providers to offer an optional informational interconnection study to serve as additional information for prospective interconnection customers in deciding whether to submit an interconnection request and set minimum requirements for transmission providers to publicly post available information pertaining to generator interconnection;[49] (2) require transmission providers to implement a first-ready, first-served cluster study process that allocates costs associated with cluster studies and identified network upgrades consistent with the discussion below;[50] and (3) impose more stringent financial commitments and readiness requirements on interconnection customers, including increased study deposits, more stringent site control requirements, a commercial readiness framework, and higher withdrawal penalties.[51] To implement these reforms, the Commission also proposed to require transmission providers to establish a transition process.[52]

22. Second, the Commission proposed three reforms to increase the speed of interconnection queue processing, including: (1) revisions to eliminate the reasonable efforts standard for interconnection study processing;[53] (2) revisions to establish an

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[48] NOPR, 179 FERC ¶ 61,194 at P 4.

[49] *Id.* PP 42-52.

[50] *Id.* PP 56-101.

[51] *Id.* PP 104-148.

[52] *Id.* PP 150-160.

[53] *Id.* PP 168-173.

affected system study process, along with necessary *pro forma* affected system agreements;[54] and (3) revisions to establish an optional resource solicitation study.[55]

23. Finally, the Commission proposed three reforms to incorporate technological advancements into the interconnection study process. With these reforms, the Commission proposed to require transmission providers to: (1) increase flexibility in the generator interconnection process by allowing generating facilities to co-locate, allow the interconnection customer to request the addition of a generating facility to an existing interconnection request, increase the availability of surplus interconnection service, and allow interconnection customers to propose operating assumptions for their generating facilities;[56] (2) incorporate the enumerated alternative transmission technologies into the interconnection study process at the request of the interconnection customer;[57] and (3) list required modeling standards for inclusion in all interconnection requests that include inverter-based resources (IBRs), as well as require certain performance standards from IBRs during system disturbances.[58]

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[54] *Id.* PP 182-215.

[55] *Id.* PP 223-237.

[56] *Id.* PP 242-288.

[57] *Id.* PP 297-302.

[58] *Id.* PP 328-341.

24. In response to the NOPR, 189 comments were filed.[59] These comments have informed our determinations in this final rule.

D. Joint Federal-State Task Force on Electric Transmission

25. On June 17, 2021, the Commission established a Joint Federal-State Task Force on Electric Transmission (Task Force) to formally explore broad categories of transmission-related topics.[60] The Commission explained that the development of new transmission infrastructure implicated a host of different issues, including generator interconnection. The Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions nominated by the National Association of Regulatory Utility Commissioners (NARUC), with two originating from each NARUC region.[61] The Task Force convenes for multiple formal meetings annually, which are open to the public. Since its creation and as of the date of issuance of this final rule, the Task Force has met seven times.

26. The discussion at the May 2022 meeting focused on interconnection issues, including generator interconnection queue processes and backlogs. The Task Force

[59] Appendix A lists the entities that submitted comments on the NOPR and the shortened names used through this final rule to describe those entities.

[60] *Joint Fed.-State Task Force on Elec. Transmission*, 175 FERC ¶ 61,224, at PP 1, 6 (2021).

[61] An up-to-date list of Task Force members, as well as additional information on the Task Force, is available on the Commission's website at: https://www.ferc.gov/TFSOET. Public materials related to the Task Force, including transcripts from public meetings, are available in the Commission's eLibrary in Docket No. AD21-15-000.

members discussed: the primary challenges preventing more efficient processing of interconnection queues; specific improvements to interconnection processes (such as tighter applicant requirements to enter and remain in the queue, clustering, fast tracking, tighter deadlines on transmission providers completing studies, and minimizing reiterative studies); and how to balance near-term improvements to the interconnection procedures with longer-term regional transmission planning and development.[62]

II. Overall Need for Reform

A. NOPR

27. In the NOPR, the Commission noted that the serial first-come, first-served study process was adopted at a time when most interconnection requests were for large traditional generating facilities that would use readily available transmission capacity.[63] The Commission stated that the continued use of this process in the face of dramatic changes to the electric power industry, principally the surge in interconnection requests, the rapidly changing resource mix, evolving market forces, and the emergence of new technologies, has led to a growing backlog of interconnection requests and study delays for many transmission providers.[64] The Commission also stated that these interconnection queue backlogs and study delays create uncertainty and inhibit project

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[62] *Joint Fed.-State Task Force on Elec. Transmission*, Notice of Meeting, Docket No. AD21-15-000 (issued Apr. 22, 2022).

[63] NOPR, 179 FERC ¶ 61,194 at P 18.

[64] *Id.* PP 18-20.

developers' ability to interconnect generating facilities to the transmission system.[65] The Commission preliminarily found that the existing *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA may be insufficient to ensure that new generating facilities are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner and to thereby ensure that rates, terms, and conditions for Commission-jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.[66] Further, because the interconnection queue backlogs and study delays afflicting generator interconnection service nationwide hinder the timely development of new generation and thereby stifle competition in the wholesale electric markets, the Commission also preliminarily found that the Commission's *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA result in rates, terms, and conditions in the wholesale electric markets that are unjust, unreasonable, and unduly discriminatory or preferential.

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[65] *Id.* P 19 (citing Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, Tr. 15:21-16:1 (Ted Thomas) (May 6, 2022) (May Joint Task Force Tr.) ("Houston, we have a problem. As stated in the NARUC ANOPR comments, existing methods for interconnecting new resources to the transmission grid are inadequate and inefficient because of the time necessary to interconnect new resources and the corresponding network upgrade costs.")).

[66] *Id.* P 22 (citing May Joint Task Force Tr. 23:6-11 (Riley Allen) ("Ultimately, this system is not working efficiently now and those inefficiencies translate into costs. It's not just cost on the developers, but I find from my decades of experience that, if there are inefficiencies in the system, they ultimately have to be borne by the loads and ratepayer interests.")).

28. The Commission stated that its preliminary findings were based on several features of the Commission's existing generator interconnection procedures and agreements that are of concern, specifically: (1) the information (or lack thereof) available to prospective interconnection customers and the commitments required of them to enter and progress through the interconnection queue; (2) the reliance on a serial first-come, first-served study process and the standard to which transmission providers are held for meeting interconnection study deadlines; (3) the protocols for affected systems studies; (4) the provisions for studying new or hybrid generation technologies and considering alternative transmission technologies; and (5) the performance requirements for non-synchronous generating facilities, including wind, solar, and electric storage facilities.[67]

29. The Commission found that some of the same issues persist in the small generating facility context and, therefore, proposed limited reforms to the *pro forma* SGIP and *pro forma* SGIA to incorporate alternative transmission technologies into the interconnection process and to provide modeling and performance requirements for non-synchronous generating facilities.[68]

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[67] *Id.* PP 23-36 (citing May Joint Task Force Tr. 70:20-71:6 (Matthew Nelson) (analogizing reiterative studies to going to the supermarket to buy ingredients for a recipe without knowing how much the ingredients cost, finding out at the register that they cost too much for your budget, and having to "go home, get a new recipe, and start it all over again")).

[68] *Id.* P 5.

B. Comments

30. The vast majority of commenters overwhelmingly agree with the Commission's preliminary conclusion that there is a need to reform the Commission's *pro forma* interconnection procedures and agreements to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, thereby ensuring that rates, terms, and conditions for Commission-jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.[69] These commenters generally agree that the unprecedented volume of

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[69] ACE-NY Initial Comments at 2; ACE-NY Reply Comments at 5; AEE Initial Comments at 3, 5; AEE Reply Comments at 5; AES Initial Comments at 2; Affected Interconnection Customers Initial Comments at 2; Ameren Initial Comments at 2; APPA-LPPC Reply Comments at 2; Avangrid Initial Comments at 6, 8; Bonneville Initial Comments at 3; CESA Initial Comments at 3; CESA Reply Comments at 1; Clean Energy Associations Initial Comments at 8; Clean Energy Buyers Initial Comments at 3; Clean Energy States Initial Comments at 2-3; Colorado Commission Initial Comments at 1; Consumers Energy Initial Comments at 2; Cypress Creek Initial Comments at 1; Dominion Initial Comments at 4; EEI Initial Comments at 2; EEI Reply Comments at 3; EDF Renewables Initial Comments at 1-2; Enel Initial Comments at 2; Energy Keepers Initial Comments at 2; Evergreen Action Initial Comments at 1; Eversource Initial Comments at 2; Fervo Energy Initial Comments at 2; Google Initial Comments at 2; Guzman Energy Initial Comments at 2; Hannon Armstrong Initial Comments at 1; Hydropower Commenters Initial Comments at 5; Illinois Commission Initial Comments at 2-3, 5; Interwest Initial Comments at 3; Interwest Reply Comments at 2; ISO-NE Initial Comments at 2-3; MISO TOs Initial Comments at 2, 6; NARUC Initial Comments at 3; New Jersey Commission Initial Comments at 4-9; NY Commission and NYSERDA Initial Comments at 3; NV Energy Initial Comments at 3; Ohio Commission Consumer Advocate Initial Comments at 3-4; OMS Initial Comments at 2; Ørsted Initial Comments at 5; Pine Gate Initial Comments at 8; PJM Initial Comments at 1, 4; PJM Coalition Initial Comments at 1; RWE Renewables Initial Comments at 1; Senators Hickenlooper and King Initial Comments at 1-2; Shell Initial Comments at 5-6; State Agencies Initial Comments at 1-2; TAPS Initial Comments at 1; Union of Concerned Scientists Reply Comments at 1; UMPA Initial Comments at 1; WATT Coalition Initial Comments at 1; Xcel Initial Comments at 8.

generation in the interconnection queue, which is almost equal to the current U.S. generation fleet, has resulted in severe backlogs in interconnection processes across the country.[70] For example, the Ohio Commission Consumer Advocate states that "there is an urgent need to clear the current generator interconnection queue backlog and to facilitate timely and economic interconnection of new resources in a way that responds to current and future market conditions."[71] EEI recognizes that, despite many efforts underway across the country to fix individual transmission provider interconnection queue processes, there is still a need for the Commission to address backlogs and improve certainty in the interconnection queue process.[72] Several commenters assert that these interconnection backlogs have resulted in commercial uncertainty regarding both the magnitude of identified upgrade costs and the timeline for completion of interconnection studies, delayed project development, increased costs for consumers due

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[70] AEE Initial Comments at 3; Apple Initial Comments at 1; Bonneville Initial Comments at 3; Clean Energy Buyers Initial Comments at 3; Colorado Commission Initial Comments at 2, 8-11; EDF Renewables Initial Comments at 2; Evergreen Action Initial Comments at 1; Eversource Initial Comments at 2; Interwest Initial Comments at 1-2; NV Energy Initial Comments at 2-3; Ohio Commission Consumer Advocate Initial Comments at 3-4; Ørsted Initial Comments at 2; Senators Hickenlooper and King Initial Comments at 1-2; U.S. Chamber of Commerce Initial Comments at 5; UMPA Initial Comments at 1.

[71] Ohio Commission Consumer Advocate Initial Comments at 3-4.

[72] EEI Reply Comments at 3.

to the prevention of new supply from reaching the market, and impaired reliability.[73] Senators Hickenlooper and King note that, in the past decade, 23% of proposed generating facilities reached commercial operation, while 72% were withdrawn.[74] ELCON and APPA-LPPC both argue that uncertainty, on the part of both transmission provider and generator project developer, inevitably leads to an increase in costs to consumers.[75] U.S. DOE submits a recent report published by the Lawrence Berkeley National Laboratory, which finds that interconnection costs in MISO have escalated as the number of interconnection requests has increased.[76] Specifically, the report finds that interconnection costs in MISO doubled for projects completed between 2019-2021 compared to projects completed prior to 2018, and cost estimates tripled for projects still active in the queue between the same time periods. Some commenters agree that the existing interconnection rules in the *pro forma* LGIP and *pro forma* LGIA create an

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[73] ACE-NY Initial Comments at 2; AEE Initial Comments at 4; EDF Renewables Initial Comments at 2; ELCON Initial Comments at 2; Fervo Energy Initial Comments at 2; PJM Coalition Initial Comments at 2; Xcel Reply Comments at 1.

[74] Senators Hickenlooper and King Initial Comments at 1 (citing Joseph Rand et al., Lawrence Berkeley Nat'l Lab., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection* (Apr. 2022) (Queued Up 2022), https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf)).

[75] ELCON Initial Comments at 2; APPA-LPPC Initial Comments at 2.

[76] U.S. DOE Initial Comments at 1 (citing Joachim Seel et al., Lawrence Berkeley Nat'l Lab., *Interconnection Cost Analysis in the MISO Territory* at 1 (Oct. 2022)).

incentive for interconnection customers to submit interconnection requests even if they are not prepared to move forward with their projects, in order to secure a favorable position in the interconnection queue or in an attempt to obtain locations with available transmission capacity.[77] They assert that the withdrawal of each speculative interconnection request triggers reassessments and possible restudies by the transmission provider that can increase the timing and interconnection cost for lower-queued interconnection requests. Several commenters point to ambitious climate goals (such as the United States' commitment to reducing net greenhouse gas emissions by 50-52% by 2030 under the Paris Climate Agreement) and argue that: (1) these changes will likely spur greater investment in new generation and exacerbate the delays in processing interconnection requests; and/or (2) without an efficient and transparent interconnection process, none of the clean energy generating facilities intended to meet these goals can be

[77] Clean Energy Buyers Initial Comments at 3; Dominion Initial Comments at 4-5; PJM Initial Comments at 12; U.S. Chamber of Commerce Initial Comments at 4-5.

effectively deployed.[78] Consumers Energy argues that delays in processing interconnection requests will exacerbate resource adequacy challenges.[79]

31. A small subset of commenters, while supporting an overall need for reform, disagree with some of the Commission's preliminary conclusions about the need for reform.[80] A few other commenters claim that there is no basis for the Commission's preliminary conclusion that speculative projects that enter the interconnection queue and later withdraw, causing cascading restudies, are responsible for interconnection queue

[78] AEP Initial Comments at 2; Affected Interconnection Customers Initial Comments at 2; Allen Meyer Initial Comments at 1; Apple Initial Comments at 1; Bretton C Little Initial Comments at 1; Colorado Commission Initial Comments at 13-14; EDF Renewables Initial Comments at 2-3 (referencing Inflation Reduction Act, Pub. L. No. 117-169 (2022)); ELCON Initial Comments at 2; Evergreen Action Initial Comments at 2; GSCE Initial Comments at 5-6; Individual Signatories Initial Comments at 1-2; Interwest Comments at 1-2; National Grid Initial Comments at 2; Payton Alaama Reply Comments at 1; Pine Gate Reply Comments at 3-4; Rick K Lathrop Reply Comments at 1; Shell Initial Comments at 6; State Agencies Initial Comments at 8-9 (citing Int'l Energy Agency, *Net Zero by 2050: A Roadmap for the Global Energy Sector* (2021) https://www.iea.org/reports/net-zero-by-2050; *The United States' Nationally Determined Contribution* (2021), https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/United%20States%20NDC%20April%2021%202021%20Final.pdf; White House, *FACT SHEET: Biden Administration Jumpstarts Offshore Wind Energy Projects to Create Jobs* (Mar. 29, 2021), https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/29/fact-sheet-biden-administration-jumpstarts-offshore-wind-energy-projects-to-create-jobs/); Sue Hilton Initial Comments at 1; Union of Concerned Scientists Reply Comments at 6; Vistra Initial Comments at 4.

[79] Consumers Energy Initial Comments at 7.

[80] For instance, Affected Interconnection Customers disagree with the Commission's reference to a nationwide shortage of qualified engineers and contend that the Commission fails to support this conclusion with any evidence beyond statements made by CAISO and MISO. Affected Interconnection Customers Initial Comments at 14 (citing NOPR, 179 FERC ¶ 61,194 at P 20 n.67).

backlogs.[81] A few commenters assert that the Commission did not take into account pertinent factors affecting interconnection queue sizes, such as an increase in the development of smaller, more diverse generating facilities.[82]

32. Three comments note that various transmission providers use vastly different interconnection procedures from the *pro forma* procedures established in Order No. 2003 and argue that there is an insufficient legal foundation under FPA section 206 to demonstrate that all of these approved interconnection procedures are unjust, unreasonable, and unduly discriminatory or preferential.[83] Southern disagrees entirely with the Commission's preliminary conclusion that there is a need for reform.[84] Southern argues that the Commission based its proposed actions in the NOPR on conjecture and thus failed to provide substantial evidence or engage in reasoned decision-making to demonstrate that the current interconnection processes are unjust and unreasonable.[85] In

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[81] CREA and NewSun Initial Comments at 35-37 (countering that interconnection requests do not reach commercial operation due to other reasons such as permitting or financing difficulties); NextEra Initial Comments at 4; Public Interest Organizations Initial Comments at 1-7 (arguing that the rate of queue withdrawal has been consistent over the last decade); SEIA Reply Comments at 1.

[82] AEE Initial Comments at 6-7; Pine Gate Reply Comments at 4; SEIA Reply Comments at 1.

[83] Early Adopters Coalition Initial Comments at 1-2; PacifiCorp Initial Comments at 9; Southern Initial Comments at 10-11.

[84] Southern Initial Comments at 10-12; Southern Reply Comments at 1, 4.

[85] Southern Initial Comments at 10 (citing *Emera Me. v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017)); Southern Reply Comments at 1, 4.

addition, Southern contends that the Commission's proposals are arbitrary and capricious because they impose a broadly applicable remedy to a problem that does not exist uniformly.[86]

33. Southern further asserts that the Commission failed to provide any actual evidence that its proposals will reduce interconnection queue backlogs or increase certainty for interconnection customers.[87]

34. Some commenters argue that the sum of the NOPR may actually slow study processes, increase backlogs, and may unintentionally increase costs to ratepayers.[88] For example, CAISO asserts that shortening study timelines results in rushed, unreliable studies which would ultimately require more iteration and longer interconnection queue processing times.[89] Additionally, NextEra argues that the NOPR provides few, if any, solutions relevant to those regions that have already implemented cluster studies yet continue to experience significant study delays.[90] Further, some commenters oppose any

[86] Southern Initial Comments at 11-12.

[87] *Id.* at 10; Southern Reply Comments at 5.

[88] CAISO Initial Comments at 3; Dominion Initial Comments at 7; New York State Department Initial Comments at 2; NextEra Reply Comments at 2; NRECA Initial Comments at 7.

[89] CAISO Initial Comments at 3.

[90] NextEra Reply Comments at 7.

generic one-size-fits-all reform, arguing that queue reform is best left to the regional level.[91]

35. Several commenters generally support the suite of proposed reforms in their entirety.[92] As discussed in detail in each section below discussing individual reforms, most commenters either support specific proposals or suggest that the Commission prioritize certain proposed reforms. For instance, Consumers Energy supports reforms that increase the speed of interconnection queue processing because it claims that the reforms provide clarity for resource planners and interconnection customers as well as improve the reliability of the bulk electric system and the clean energy resource transformation.[93] Google urges the Commission to prioritize reforms that provide a level playing field for both utility-backed resources and independent power producer-developed resources.[94] Google also expresses concern that the layering of increased study deposits, more stringent site control requirements, the proposed commercial readiness requirements, and withdrawal penalties may place undue burden on interconnection customers if the Commission does not also adopt proposals for more

[91] Avangrid Initial Comments at 36-37; Southern Initial Comments at 14-15.

[92] APPA-LPPC Initial Comments at 2-3; APPA-LPPC Reply Comments at 2; Apple Initial Comments at 1; ACORE Initial Comments at 2; Amazon Initial Comments at 2; Evergreen Action Initial Comments at 1-4; Individual Signatories Initial Comments at 1; PJM Coalition Initial Comments at 2.

[93] Consumers Energy Initial Comments at 10-11.

[94] Google Initial Comments at 3.

publicly available interconnection information, firm study deadlines, and penalties for missed study deadlines.[95]

36. Some commenters support adopting most or all of the limited reforms to the *pro forma* SGIP and *pro forma* SGIA proposed in the NOPR.[96] For instance, Microgrid Resources asserts that including the proposed reforms in the *pro forma* SGIP is necessary to reflect the operating assumptions of, and to provide equitable treatment for, microgrids and other behind-the-meter resources.[97] Microgrid Resources asserts that, if the Commission succeeds in expediting interconnections for large generating facilities, while small generating facility interconnections languish, it will bias the system against smaller local generating facilities that are the backbone of community resilience.

C. <u>Commission Determination</u>

37. Based on the record, including comments submitted in response to the NOPR, as discussed below, we find that there is substantial evidence to support the conclusion that the existing *pro forma* generator interconnection procedures and agreements are unjust,

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[95] *Id.* at 16.

[96] Bonneville Initial Comments at 24 (supporting applying some of the Commission's proposed reforms to the *pro forma* SGIP and *pro forma* SGIA (*e.g.*, commercial readiness requirements), but asking that transmission providers be granted flexibility to determine which reforms should be applicable to small generator procedures and agreements); IREC Initial Comments at 3 (stating that the *pro forma* SGIP lacks the necessary provisions to safely and reliably interconnect storage to the electric grid while enabling its unique operating characteristics); Microgrid Resources Initial Comments at 8-9; Xcel Initial Comments at 19 (supporting applying reforms to small generating facilities requesting energy only interconnection service).

[97] Microgrid Resources Initial Comments at 8-9.

unreasonable, and unduly discriminatory or preferential.[98] We therefore adopt the preliminary findings in the NOPR concerning the need for reform[99] and, pursuant to FPA section 206, conclude that certain revisions to the *pro forma* open access transmission tariff and the Commission's regulations are necessary to ensure rates that are just, reasonable, and not unduly discriminatory or preferential. Specifically, we find that the existing *pro forma* generator interconnection procedures and agreements are insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, thereby ensuring that rates, terms, and conditions for Commission-jurisdictional services are just, reasonable, and not unduly discriminatory or preferential. Absent reform, the current interconnection process will continue to cause interconnection queue backlogs, longer development timelines, and increased uncertainty regarding the cost[100] and timing of interconnecting to the transmission system. These backlogs and delays, and the resulting timing and cost uncertainty,[101] hinder the timely development of new generation and thereby stifle

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[98] 16 USC 824e(a); 18 CFR 385.206 (2022).

[99] NOPR, 179 FERC ¶ 61,194 at PP 18-36.

[100] *See* May Joint Task Force Tr. 74:9-21 (Andrew French) (stating that generator developers complain principally about cost certainty and cost sharing and that "cost certainty is the much bigger issue" given that "an essential element of being able to sell a product is to know what your inputs are so you can market it").

[101] *See* May Joint Task Force Tr. 23:18-25 (Jason Stanek) (expressing frustration with the status quo and agreement that it is "no longer tenable" considering the inability of generators to interconnect in a timely manner, e.g., there are "2,500 projects under study [in the MACRUC region] and about a half of them have been in the queue since at

competition in the wholesale electric markets resulting in rates, terms, and conditions that are unjust, unreasonable, and unduly discriminatory or preferential.

38. Indeed, recent data support the Commission's preliminary findings in the NOPR that the dramatic increase in the number of interconnection requests and limited transmission capacity are increasing interconnection queue backlogs across all regions of the country.[102] As of the end of 2022, there were over 10,000 active interconnection requests in interconnection queues throughout the United States, representing over 2,000 gigawatts (GW) of potential generation and storage capacity.[103] This potential generation is the largest interconnection queue size on record, more than four times the total volume (in GW) of the interconnection queues in 2010, and a 40% increase over the interconnection queue size from just the year prior.[104] These trends are not exclusive to any one region of the country. Instead, every single region has faced an increase in both interconnection queue size and the length of time interconnection customers are spending

least 2001").

[102] Joseph Rand et al., Lawrence Berkeley Nat'l Lab., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, at 7-8 (Apr. 2023) (Queued Up 2023), https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf; *see also* Order No. 845, 163 FERC ¶ 61,043 at P 305 (requiring transmission providers to post interconnection study metrics). *See* Appendix B to this final rule, which provides an overview of recent data based on reporting by transmission providers in compliance with Order No. 845.

[103] Queued Up 2023 at 7-8.

[104] *Id.* at 10.

in the interconnection queue prior to commercial operation in recent years.[105] This is true for RTO/ISO and non-RTO/ISO regions alike. The non-RTO/ISO west and southeast regions both have faced queue size increases ranging from tripling to a 12-fold increase while also seeing longer timelines between interconnection requests and commercial operation dates.[106] Furthermore, the uncertainty and delays in the interconnection queues have resulted in fewer than 25% of interconnection requests, by capacity, reaching commercial operation between 2000 and 2017 in *any* region of the country—with some regions as low as 8%.[107]

39. Additionally, recent data continue to show that interconnection customers are waiting longer in the interconnection queue before withdrawing their interconnection requests,[108] even as overall interconnection study timelines are increasing in many regions.[109] For example, AEE states that, as of February 2022, all 2,274 projects waiting for an interconnection agreement in the PJM interconnection queue had been waiting for a year or more; 33% (758 projects) had been waiting more than 500 days, 22% (497 projects) have been stuck for more than two years, and 7% (166 projects) have been

[105] *Id*. at 9, 32.

[106] *Id*. at 9, 32.

[107] *Id.* at 3, 21.

[108] *Id.* at 25 (reporting that, although the median withdrawal duration has been relatively consistent over time, the mean withdrawal duration and distributions have edged higher in recent years).

[109] *Id.* at 27.

waiting more than three years.[110] NV Energy explains that several western utilities that are not currently part of an RTO/ISO are experiencing an unprecedented high volume of requests in excess of the utility's peak load.[111] AEE notes that wait times for generating facilities in interconnection queues nationwide have increased from 2.1 years for generating facilities built in 2000-2010 to 3.7 years for those built in 2011-2021.[112] And despite efforts to address these challenges,[113] interconnection queue backlogs and delays

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[110] AEE Initial Comments at 4 (citing Advanced Energy Economy, "In PJM, Renewable Energy Projects Are Getting Stuck" (February 2022), https://blog.aee.net/in-pjm-renewable-energy-projects-are-getting-stuck).

[111] NV Energy Initial Comments at 2-3. NV Energy explains that it has a peak load of 9,400 MW with an interconnection queue backlog for projects totaling more than 27,000 MW; Idaho Power has a peak load of 3,751 MW with an interconnection queue backlog of over 18,000 MW; PacifiCorp has a peak load of 13,000 MW with an interconnection queue backlog of over 45,000 MW; and APS has a peak load of 7,600 MW with an interconnection queue backlog of over 50,000 MW.

[112] AEE Initial Comments at 4 (citing Queued Up 2022); *see also* ACE-NY Initial Comments at 2 (arguing that the ability of New York to meet its clean energy goals is threatened by an interconnection process that is too slow); Affected System Interconnection Customers Initial Comments at 2 (stating that Affected System Interconnection Customers have navigated the generator interconnection queues of various transmission providers around the country and experienced firsthand the inefficiencies and delays, which represent the greatest obstacle to achieving commercial operation of a new energy project); GSCE Initial Comments at 5-6 (contending that an average of 6,000 MW of new solar, wind, and batteries must be added each year until 2045 to reach California's electric sector carbon-neutrality requirement, but that over the past decade California has only succeeded with adding an average of 1,000 MW of utility-scale solar and 300 MW of wind to the transmission system each year).

[113] Order No. 845, 163 FERC ¶ 61,043 at P 24.

have persisted and worsened. For generating facilities built in 2022, wait times in the interconnection queue saw a marked increase to now roughly five years.[114]

40. Delays in the interconnection study process are an important contributor to interconnection queue backlogs nationwide. For instance, based on the recent interconnection study metrics transmission providers posted in compliance with Order No. 845, of the 2,179 interconnection studies completed in 2022, 68% were issued late.[115] Furthermore, at the end of 2022, an additional 2,544 studies were delayed (i.e., ongoing and past their deadline).[116] All of the RTOs/ISOs except CAISO and 14 non-RTO/ISO transmission providers reported delayed studies at the end of 2022.[117]

41. Consistent with the NOPR, we find that numerous factors have contributed to the increasing volume of interconnection requests, including a rapidly changing resource

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[114] Queued Up 2023 at 31; *see also* Shell Initial Comments at 6 (describing multiple instances of five to six years until execution of an interconnection agreement, four years waiting for an initial "kick-off" call, two years waiting for a feasibility study, three years waiting for a system impact study, and over two years waiting for a facilities study).

[115] This is based on data provided by transmission providers in compliance with Order No. 845. See Appendix B to this final rule for the underlying data. Note that data from SPP is omitted here and in follow-on references to Order No. 845 data in this determination. This is because during 2022, SPP was transitioning to a new interconnection study process, and thus its data is not comparable to the other transmission providers.

[116] *Id.* Note that the vast majority of these studies (2,211) were in PJM.

[117] *Id.* CAISO revised the interconnection study deadlines of their queue cluster 14 to account for the unprecedented increase in interconnection requests. *Cal. Indep. Sys. Operator Corp.*, 176 FERC ¶ 61,207 (2021).

mix, market forces, and emerging technologies. For example, the interconnection queues in all parts of the country are now predominantly made up of comparatively new technologies that have operating characteristics and generally shorter construction cycles that were not taken into account when the Commission issued Order No. 2003, such as solar, battery storage, and hybrid resources, as older, larger generating facilities retire.[118] The Colorado Commission notes that solar projects account for roughly half of the cumulative requests in the five RTO/ISO queues and likely an even greater percentage of the most recent requests.[119] In addition to the drastic increase in the number of interconnection requests in all regions of the country, evidence shows that interconnection studies have increased in complexity since the Commission issued Order No. 2003, potentially straining transmission provider resources.[120] At the same time, we find that available transmission capacity has been largely or fully utilized in many regions, creating situations where interconnection customers face significant network

[118] Queued Up 2023 at 9; *see also* Colorado Commission Comments at 9 (stating that the growth of solar project interconnection requests is a significant cause of the overall supply and demand imbalance across all RTOs/ISOs as well as other regions).

[119] Colorado Commission Initial Comments at 9.

[120] *See, e.g.*, NYISO Initial Comments at 6-7 (stating that "[s]tudies are only becoming more complex with the expanding scope of ISO/RTOs' interconnection responsibilities"); Xcel Initial Comments at 7 (stating that "in many cases study models with large clusters are difficult to solve . . . Ensuring new transmission lines are realistic and even validating substation designs and locations takes significant work to be done properly").

upgrade cost assignments to interconnect their proposed generating facilities.[121] For example, as referenced by the U.S. DOE, a recent report finds that interconnection costs in MISO doubled for generating facilities for which the interconnection studies were completed between 2019 and 2021 as compared to those completed prior to 2019, and cost estimates tripled for proposed generating facilities still active in the interconnection queue between the same time periods.[122] These cost increases are similar to those being faced in NYISO and PJM, where interconnection costs, per kW, have doubled (or more) for recently completed generating facilities.[123] As a result, we find that this combination of increased volume of diverse interconnection requests and insufficient transmission capacity leading to higher costs to interconnect, which can result in interconnection

[121] *See*, *e.g.*, ACORE Initial Comments at 2 (noting that "upgrades based on generation interconnection may be a sub-optimal, expensive, and ultimately ineffective way to accomplish transmission expansion"); AEE Initial Comments at 3 (asserting that "inefficient and impeded interconnection processes lead to unacceptable delays and artificially high interconnection costs"); EDF Renewables Initial Comments at 3.

[122] Joachim Seel et al., *Generator Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory*, at 1, 4-5 (2022), https://emp.lbl.gov/interconnection_costs.

[123] Julia Mulvaney Kemp et al., *Interconnection Cost Analysis in the NYISO Territory* (2023), https://emp.lbl.gov/publications/interconnection-cost-analysis-nyiso (showing that costs have doubled for generating facilities studied since 2017, relative to costs for generating facilities studied from 2006 to 2016); Joachim Seel et al., *Interconnection Cost Analysis in the PJM Territory* (2023), https://emp.lbl.gov/publications/interconnection-cost-analysis-pjm (showing that costs for recent "complete" generating facilities have doubled on average relative to costs from 2000-2019).

request withdrawals, has resulted in longer interconnection queue processing times and larger, more delayed interconnection queues.

42. In response to comments asserting that the Commission did not take into account other factors affecting interconnection queue sizes, such as the development of smaller, more diverse generating facilities, in its preliminary findings on the need for reform in the NOPR,[124] we find that the record shows that interconnection queue sizes are increasing in both number of interconnection requests and in total MW capacity in all regions of the country and such increases are not due to an influx of any particular size of proposed generating facility. Moreover, data show that the median duration for all generating facilities that enter the interconnection queue hovers around 30 months, independent of the size of the interconnection request.[125]

43. Interconnection queue backlogs and delays have created uncertainty for interconnection customers regarding the timing and cost of ultimately interconnecting to the transmission system. We agree with commenters that such uncertainty, on the part of both transmission provider and interconnection customer, may lead to an increase in costs

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[124] *See, e.g.*, Pine Gate Reply Comments at 4 (stating that "the days of . . . large, conventional resources are waning as the majority of interconnection requests are now comprised of smaller, more diverse resource" and that "[l]arger interconnection queues are, to a certain extent, a natural byproduct of this change"); SEIA Reply Comments at 1 (contending that interconnection requests have increased in number "because newer projects are smaller and have less capacity" and "[m]ore interconnection requests are needed to integrate the same amount of generation capacity into the grid").

[125] Queued Up 2023 at 29.

to consumers.[126] First, delayed interconnection study results or unexpected cost increases can disrupt numerous aspects of generating facility development.[127] Cost uncertainty poses an especially significant obstacle because interconnection customers may not be able to finance substantial increases in unexpected interconnection costs. Second, transmission providers may face uncertainty regarding the size and makeup of the interconnection queue and the commercial viability of the project in the interconnection queue, creating inefficiencies in the study process, increasing interconnection study costs, and delayed study results. Such uncertainty, either on the part of transmission providers or interconnection customers, are ultimately passed through to consumers through higher transmission or energy rates.[128] Increases in energy rates may result from wholesale customers having limited access to new and more competitive supplies of generation. Conversely, efficient interconnection queues and well-functioning wholesale markets deliver benefits to consumers by driving down wholesale electricity costs.

44. As the interconnection queue backlogs and study delays continue and even increase, we find that the Commission's existing rules contained in the *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA result in rates, terms, and

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[126] *See, e.g.*, Ameren Initial Comments at 2; ELCON Initial Comments at 2; ELCON Initial Comments at 2; Xcel Initial Comments at 8.

[127] *See, e.g.*, Interwest Initial Comments at 8 (contending that "[t]he harm to interconnection customers associated with interconnection study delays can be significant and costly, including liquidated damages if compliance with a commercial operation deadline is at risk").

[128] Ameren Initial Comments at 2.

conditions for Commission-jurisdictional services that are unjust, unreasonable, and unduly discriminatory or preferential. Not only do the problems described above lead to an inability of interconnection customers to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, they also hinder the timely development of new generation, thereby stifling competition in the wholesale electric markets. We, therefore, find that reform to the Commission's existing *pro forma* generator interconnection procedures and agreements is necessary.

45. Our findings that the existing *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA must be reformed are based on the following features of these existing rules: (1) the information (or lack thereof) available to prospective interconnection customers and the commitments required of them to enter and progress through the interconnection queue; (2) the reliance on a serial first-come, first-served study process and the "reasonable efforts" standard that transmission providers are held to for meeting interconnection study deadlines; (3) the protocols (or lack thereof) for affected system studies; (4) the provisions for studying new generating facility technologies and evaluating the list of alternative transmission technologies enumerated in this final rule; and (5) the modeling or performance requirements (or lack thereof) for non-synchronous generating facilities, including wind, solar, and electric storage facilities. We discuss each of these five features below.

46. First, we find that existing *pro forma* generator interconnection procedures and agreements fail to contain a process by which an interconnection customer can obtain information about potential interconnection costs at a specific location or point of

interconnection prior to submitting an interconnection request. Without this information, it is difficult for interconnection customers to assess the commercial viability of a specific proposed generating facility prior to entering the interconnection queue.[129] Furthermore, we find that for interconnection customers, the *pro forma* interconnection procedures and agreements fail to include meaningful financial commitment requirements to enter and stay in the interconnection queue and lack of stringent requirements to establish the commercial viability of proposed generating facilities.[130] As a result, interconnection customers often submit multiple interconnection requests for proposed generating facilities at various points of interconnection, knowing that not all of the proposed generating facilities will reach commercial operation, as an exploratory mechanism to obtain information to allow the interconnection customer to choose to proceed with the interconnection request representing the most favorable site in terms of potential interconnection-related costs.[131] For instance, recent interconnection study

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[129] *See, e.g.*, Fervo Energy Initial Comments at 2-3 (stating that "the incidence of interconnection applications simply intended to solicit information discovery from the transmission provider . . . is a significant defect in today's queue process"); Google Initial Comments at 4 (asserting that "there is extreme information asymmetry in the interconnection process," with transmission owners and their affiliates having greater access than independent power producers to information on the relative cost of interconnection at different points).

[130] *See, e.g.*, Dominion Initial Comments at 4 (stating that "owners of speculative projects remain in the queue process for as long as they possibly can in the hopes that their project somehow becomes viable"); U.S. Chamber of Commerce Initial Comments at 5 (concurring with the NOPR that there is a "lack of stringent financial commitments and readiness requirements on interconnection customers").

[131] *See, e.g.*, Clean Energy Associations Initial Comments at 11 (stating that "[i]n most cases, customers must actually enter the queue to ascertain what upgrade costs they

metrics posted by transmission providers continue to show that some interconnection customers are withdrawing interconnection requests before any studies are completed.[132] While interconnection customers may withdraw at any stage of the interconnection process, to do so before any study is completed indicates that interconnection customers may lack information prior to entering the interconnection queue and are entering to obtain valuable information about the commercial viability of their proposed projects vis-à-vis other interconnection customers in the queue or cluster.

47. Second, the existing serial first-come, first-served study process in the *pro forma* LGIP requires transmission providers to process interconnection requests in the order in which the transmission provider receives them. This approach creates incentives for interconnection customers to submit exploratory or speculative interconnection requests pursuant to which interconnection customers seek to secure valuable queue positions as early as possible, even if they are not prepared to move forward with the proposed generating facility. Such generating facilities are often not commercially viable and, thus, the interconnection customers ultimately withdraw from the interconnection queue.

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will be responsible for"); Clean Energy Buyers Initial Comments at 3 (stating that inefficiencies in the serial study queue are "compounded by exploratory interconnection requests that are based on developers' attempts to obtain locations with available transmission capacity"); NY Commission and NYSERDA Initial Comments at 6-7 (stating that "increased access to valuable information . . . could deter developers from submitting multiple, speculative [interconnection requests]").

[132] Based on data provided by transmission providers in compliance with Order No. 845 (showing that 35% of withdrawals in 2022 took place before any studies had been completed). See Appendix B to this final rule for the underlying data.

We agree with commenters that the withdrawal of speculative interconnection requests that trigger reassessments and possible restudies by the transmission provider can delay the timing and increase the cost to interconnect for lower-queued interconnection requests.

48. In summary, we find that the lack of (1) access of information about a specific location or point of interconnection prior to submitting an interconnection request and (2) meaningful financial commitments in the *pro forma* interconnection procedures and agreements for interconnection customers to enter and stay in the interconnection queue, as well as the existing serial first-come, first-served study process, all incentivize interconnection customers to submit speculative interconnection requests that contribute to interconnection study backlogs, delays, and uncertainty, and, in turn, unjust and unreasonable Commission-jurisdictional rates.

49. We disagree with commenters' assertions that there is no basis to find that speculative interconnection requests are responsible for interconnection queue backlog and delays. We highlight that more than 70% of interconnection requests were withdrawn from the interconnection queue between 2000 and 2017.[133] Although we recognize that there are various reasons an interconnection customer may withdraw its request from the interconnection queue, a withdrawal indicates an inability to reach commercial operation. Because a withdrawal can trigger costly restudies and create

[133] Queued Up 2023 at 18 (reporting that 72% of all interconnection requests submitted from 2000-2017 were withdrawn).

uncertainty in the interconnection process for interconnection customers and transmission providers alike, withdrawals of commercially non-viable interconnection requests from the interconnection queue is a significant contributing factor to interconnection queue backlogs and delays.[134] Late-stage withdrawals of interconnection requests are also increasing.[135] Late-stage withdrawals present a significant problem, as they can trigger restudies for other interconnection customers that can result in significant increases to the interconnection costs attributed to those customers and the timeline for completion of interconnection studies, which can result in further late-stage withdrawals, thus exacerbating the interconnection queue backlogs and delays.[136]

50. We also find that interconnection queue backlogs and delays, and the accompanying uncertainty, are further compounded because transmission providers have limited incentive to perform interconnection studies in a timely manner. Under the *pro forma* LGIP, transmission providers are held to a "reasonable efforts" standard in completing interconnection studies consistent with their tariff-imposed deadlines. However, this standard offers significant discretion to the transmission providers in extending their own deadlines. The record demonstrates that a majority of transmission

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[134] *See, e.g.*, Ohio Commission Consumer Advocate Initial Comments at 8 (stating that "[e]ach withdrawn project entails PJM restudy on lower-queued projects, which delays the processing of new service queues and may have the consequence of a cascade of withdrawals").

[135] Queued Up 2023 at 22.

[136] *See, e.g.*, AEE Initial Comments at 4-5; Queued Up 2023 at 22.

providers across the country regularly fail to meet interconnection study deadlines.[137] Despite pervasive delays in completing interconnection studies by transmission providers, we acknowledge that transmission providers have faced few, if any, consequences for failing to meet their tariff-imposed study deadlines under the reasonable efforts standard.[138] This outcome stands in stark contrast to interconnection customers that face financial and commercial consequences due to late interconnection study results and may be considered withdrawn from the interconnection queue for failing to meet their tariff-imposed deadlines.[139] For these reasons, we find that the existing *pro forma* LGIP requirement for transmission providers to make a reasonable effort to meet interconnection study deadlines contributes to the interconnection study backlogs, delays, and uncertainty that erects barriers to new generation.[140] Therefore, we

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[137] For example, based on data submitted by transmission providers in compliance with Order No. 845, 80% of transmission providers had delayed studies in at least one of the past three years (2020-2022) and 57% had delayed studies in at least two. *See* Appendix B, tbls. 3 & 4. *See also* NARUC Initial Comments at 13 (stating "nearly all transmission providers across the country, including many transmission providers that have implemented queue reforms, regularly fail to meet interconnection study deadlines").

[138] *See, e.g.*, Clean Energy Associations Initial Comments at 43-44 (stating that "[a]t present, there is no specific incentive for delivering on-time and accurate studies, and late or inaccurate studies bring few if any consequences").

[139] *See, e.g.*, ACE-NY Initial Comments at 3 ("Project developers have strict deadlines they must adhere to in the interconnection process, with penalties that include the forced withdrawal of the project from the queue.").

[140] *See, e.g.*, NARUC Initial Comments at 13-14 (contending that "the tendency to miss deadlines introduces uncertainty in a process that is important to bringing new generation online in a timely and cost-effective manner").

find that the use of a reasonable efforts standard in the existing *pro forma* LGIP results in Commission-jurisdictional rates that are unjust and unreasonable.

51. Third, the *pro forma* LGIP includes no requirements regarding how or when transmission providers should complete affected system studies. Without requirements, affected system studies often lag behind those completed by the transmission provider to whose transmission system the interconnection customer proposes to interconnect (the so-called host transmission provider) and are sometimes completed very late in the interconnection process, causing an additional round of delays and cost uncertainty for interconnection customers.[141] Additionally, for transmission providers that have procedures for how to complete affected system studies in their tariffs or other documents (e.g., business practice manuals or joint operating agreements), the procedures are not consistent, may be hard for interconnection customers to locate, and may not represent the actual practices in use by the transmission provider, thus still creating uncertainty for interconnection customers. As a result, we find that the lack of consistent requirements for affected system modeling and procedures results in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential.

52. Fourth, we find that the Commission's *pro forma* LGIP fails to accommodate the operating characteristics and technical capabilities of electric storage resources when it

[141] *See, e.g.*, MISO Initial Comments at 72 (stating that "the need to wait for affected systems studies is the cause of the majority of delays in the MISO study process"); May Joint Task Force Tr. 65:2-8 (Dan Scripps) (citing affected systems studies as "a growing source of delay and cost uncertainty for interconnection customers, both in terms of just the timelines involved and the difficulty in pinning those down").

comes to specific interconnection procedures and modeling. As stated above, the interconnection queues predominantly consist of new technologies which have operating characteristics that differ from synchronous resources and were not anticipated when the Commission established the *pro forma* generator interconnection procedures and agreements in Order Nos. 2003 and 2006. Specifically, electric storage resources can be charged and dispatched on a flexible, as-available basis, and are less likely than synchronous generating facilities to withdraw energy from the transmission system during peak load conditions or discharge during light load conditions.[142] However, the existing *pro forma* generator interconnection procedures and agreements do not contemplate these operating characteristics or technical capabilities of electric storage resources. As a result, we find that electric storage resources (whether standalone, co-located generating facilities, or part of a hybrid generating facility), may be studied under inappropriate operating assumptions (e.g., charging at full capacity during peak load conditions) that result in assigning unnecessary network upgrades and increased costs to interconnection customers. Therefore, we find that the Commission's *pro forma* LGIP's lack of ability to modify operating assumptions for electric storage resources results in

[142] *See, e.g.*, Bonneville Initial Comments at 22-23 (stating that "storage resources are less likely to charge during peak load conditions or discharge during light load conditions, and . . . those considerations can be factored into assumptions used in interconnection studies"); NARUC Initial Comments at 37 (stating that "assuming that an energy storage device will withdraw energy during peak demand . . . fails to recognize that those resources are likely to be highly responsive to price signals from the transmission provider and can *improve* reliability").

Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential.

53. Additionally, the record supports a finding that the existing *pro forma* interconnection procedures regarding material modifications do not provide for consistent evaluation of technology additions to an existing interconnection request.[143] We find that the record demonstrates that automatically deeming a request to add a generating facility to an existing interconnection request to be a material modification creates a significant barrier to access to the transmission system.[144] As a result, we find the existing *pro forma* LGIP and *pro forma* LGIA results in Commission-jurisdictional rates that are unjust and unreasonable.

54. Finally, the record supports a finding that the Commission's *pro forma* LGIP and *pro forma* SGIP fail to require the consideration of alternative transmission technologies that can be deployed more quickly to be used as network upgrades in place of, and at a lower cost than, traditional network upgrades.[145] In addition, commenters contend that some alternative transmission technologies could provide substantial benefits by

[143] *See, e.g.*, NARUC Initial Comments at 35 (stating that the "loss of queue position as a result of adding a generating facility that does not increase the requested service level or cause reliability issues . . . is an inefficient and discriminatory outcome").

[144] *See, e.g.*, AEE Initial Comments at 40-41; Public Interest Organizations Initial Comments at 45-47; SEIA Initial Comments at 38-39.

[145] *See, e.g.*, NARUC Initial Comments at 38 (stating that "failing to consider alternative transmission technologies that can be deployed both more quickly and at lower costs than network upgrades may render Commission-jurisdictional rates unjust and unreasonable"); OMS Initial Comments at 19 (agreeing that "failing to consider these alternative transmission technologies runs the risk of implementing longer lead-time

resolving thermal overloads and avoiding voltage collapse, allowing for better use of the existing transmission system, improving reliability, and reducing interconnection request withdrawals, restudies, and overall interconnection delays.[146] We find that failing to require transmission providers to evaluate the list of alternative transmission technologies enumerated in this final rule results in interconnection customers paying more than is just and reasonable to reliably interconnect new generating facilities, resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential. Because the benefits of the enumerated alternative transmission technologies identified above are present across all interconnection processes, regardless of the size of the interconnection request, we find that the failure to evaluate the enumerated alternative transmission technologies results in both the *pro forma* LGIP and *pro forma* SGIP being unjust, unreasonable, and unduly discriminatory or preferential.

network upgrades at a higher cost").

[146] *See, e.g.*, AEE Initial Comments at 42 (stating that alternative transmission technologies "provide benefits beyond potential cost savings, including maximizing limited rights-of-way and potentially avoiding or minimizing environmental and property impacts that can bog down siting and permitting proceedings"); Ohio Commission Consumer Advocate Initial Comments at 15 (stating that "[t]hese grid-enhancing technologies ('GETs') can improve operations, enhance system reliability, contribute to capacity, and more" and "[s]ome [grid-enhancing technologies] could provide substantial benefits by resolving thermal overloads and avoiding voltage collapse, among other things"); WATT Coalition Initial Comments at 2 (referring to the report *Unlocking the Queue with Grid Enhancing Technologies* that showed that application of the three grid-enhancing technologies in the Kansas and Oklahoma transmission systems would enable twice as much renewable energy to interconnect out of the queues without any traditional transmission upgrades.).

55. Fifth, we find that the Commission's existing *pro forma* LGIP and *pro forma* SGIP do not include a modeling requirement for non-synchronous generating facilities, which is necessary to enable the transmission provider to assess and model the facility's ability to respond appropriately to transmission system disturbances. These modeling requirements include: (1) a validated, user-defined root mean square (RMS) positive sequence dynamic model; (2) an appropriately parameterized, generic library RMS positive sequence dynamic model; and (3) a validated electromagnetic transient (EMT) model, if the transmission provider performs an EMT study as part of the interconnection study process. Additionally, we find that accurate and validated models are necessary to address study delays and to ensure that transmission providers identify the necessary interconnection facilities and network upgrades to accommodate the interconnection request and appropriate assignment of interconnection costs. As a result, we find that the lack of a modeling requirement for non-synchronous generating facilities in the *pro forma* LGIP and *pro forma* SGIP results in rates that are unjust, unreasonable, and unduly discriminatory or preferential.

56. Furthermore, the physical characteristics of synchronous generating facilities allow them to continue to inject electric current during transmission system disturbances, as required by the *pro forma* LGIA and *pro forma* SGIA.[147] However, non-synchronous generating facilities do not face a comparable requirement and many cease injecting

[147] *Pro forma* LGIA art. 9.7.3 and *pro forma* SGIA art. 1.5.7 require synchronous generating facilities to remain "connected to and synchronized with" the transmission system during system disturbances.

current through "momentary cessation," which creates reliability issues on the transmission system.[148] Moreover, without requirements for non-synchronous generating facilities to remain connected to and synchronized with the transmission system, interconnection studies may not accurately model expected behavior and identify the appropriate interconnection facilities and network upgrades to accommodate the interconnection request, skewing the assignment of interconnection costs. As a result, we find that the lack of comparable requirements for non-synchronous generating facilities to remain "connected to and synchronized with the [t]ransmission [s]ystem" in the *pro forma* LGIA and *pro forma* SGIA results in rates that are unjust, unreasonable, and unduly discriminatory or preferential.

57. In response to commenters that express broad opposition to the need for reform, we disagree with assertions that the existence of regional variation in interconnection procedures across the country creates an insufficient legal foundation under FPA section 206 to demonstrate that rates are unjust, unreasonable, and unduly discriminatory or preferential. Similarly, we disagree with assertions that reforms to the *pro forma* generator interconnection procedures and agreements are arbitrary and capricious because the problems identified herein do not exist uniformly. As an initial matter, the

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[148] *See, e.g.*, NERC Initial Comments at 9 (stating that "improper planning and operation of [non-synchronous resources] can pose a significant risk to . . . reliability" and adding that "risk mitigation measures . . . have been inconsistently adopted by industry"); MISO TOs Initial Comments at 32-33 (concurring with the Commission that "with more and more non-synchronous generation facilities entering the interconnection queue, the lack of a requirement for such resources to respond to system disturbances becomes 'more consequential'").

"Commission may rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution."[149] That some interconnection processes may fare better in the face of industry-wide challenges would be "as unastonishing as it is irrelevant."[150] The Commission may reasonably rely on rulemaking to address the systemic drivers leading to widespread interconnection queue backlogs and delays, notwithstanding regional variation among interconnection procedures.

58. Moreover, as noted above, every region of the country is seeing an increase in both interconnection queue size and the length of time interconnection customers are spending in the interconnection queue prior to commercial operation in recent years.[151] Furthermore, the uncertainty and delays in the interconnection queues have resulted in fewer than 25% of interconnection requests, by capacity, reaching commercial operation between 2000 and 2017 in any region of the country—with some regions as low as 8%.[152] For example, only 10% of interconnection requests, by capacity, have reached commercial operation in the non-RTO/ISO southeast region between 2000 and 2017.[153] Additionally, the challenges being faced across the country will be further compounded

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[149] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 67 (D.C. Cir. 2014) (quoting *Interstate Nat. Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 37 (2002)).

[150] *Id.* (quoting *Wis. Gas v. FERC*, 770 F.2d 1144, 1157 (D.C. Cir. 1985)).

[151] Queued Up 2023 at 9, 32.

[152] *Id.* at 3, 21.

[153] *Id.* at 21.

in the future given the recent spikes in interconnection queue sizes. In the non-RTO/ISO southeast region, the interconnection queue size has more than tripled between 2014 and 2022, with the increase predominantly made up of solar, storage, and hybrid generating facilities, adding potential complexity to future interconnection queue study processes.[154] To the extent existing *pro forma* interconnection procedures, such as first-come, first-served study processes, have worked in the past for smaller or less complex queues, such experience is not indicative of what will be necessary in the future to ensure that a growing number of interconnection requests are processed in a reliable, efficient, transparent, and timely manner.[155] Finally, as recognized in Order No. 2003, interconnection queue delays may "provide[] an unfair advantage to utilities that own both transmission and generation facilities,"[156] making it exceedingly necessary that interconnection delays are addressed in all regions of the country, especially those where transmission providers continue to own both transmission and generation.[157] As discussed above, because interconnection queue backlogs and delays afflict generator interconnection service nationwide, which hinders the timely development of new generation and thereby stifles competition in the wholesale electric markets, reforms are

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[154] *Id.* at 9.

[155] *See, e.g.*, Public Interest Organization Initial Comments at 17; R Street Initial Comments at 3.

[156] Order No. 2003, 104 FERC ¶ 61,103 at P 11.

[157] *See, e.g.*, Pine Gate Initial Comments at 15; AEE Reply Comments at 22.

necessary to ensure Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.

59. We are not persuaded by commenters' concerns that the reforms proposed in the NOPR, many of which we adopt in this final rule, will be counterproductive in addressing the need for reform. As discussed in more detail throughout this final rule, we believe that the reforms adopted herein, as a whole, will improve the efficiency of study processes, reduce interconnection queue backlogs, and thereby ensure just, reasonable, and not unduly discriminatory or preferential rates. We believe that, on balance, the reforms will produce efficiencies by, for example, reducing speculative interconnection requests and interconnection request withdrawals, which in turn will reduce the time and resources spent in interconnection studies and restudies thereby decreasing interconnection queue backlogs and delays. Additionally, the majority of the individual reforms that the Commission proposed in the NOPR and we adopt in this final rule have already been implemented in one or more regions in order to improve the interconnection process, demonstrating incremental improvements. This final rule uses some of these individual and incremental improvements as a basis for a broad suite of reforms that, in their entirety, have not yet been adopted by any region and we believe will ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. In some cases, such as for the commercial readiness reforms adopted in this final rule, we have significantly modified the NOPR proposal based on comments received.

60. Having concluded that the existing *pro forma* generator interconnection procedures and agreements are unjust, unreasonable, and unduly discriminatory or preferential, we turn, as we are required to do under FPA section 206,[158] to determining the replacement rate, described—at some length—below.

III. Reforms

A. Reforms to Implement a First-Ready, First-Served Cluster Study Process

1. Interconnection Information Access

a. Need for Reform

i. NOPR

61. The Commission noted its concern regarding the lack of information available to prospective interconnection customers regarding potential interconnection costs prior to submitting an interconnection request.[159] The Commission stated that, without this information, it is difficult for interconnection customers to assess the viability of a specific proposed generating facility. Subsequently, interconnection customers submit multiple speculative interconnection requests in an attempt to obtain information through the system impact study process about the costs associated with various project configurations. The Commission preliminarily found that the Commission's *pro forma*

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[158] 16 USC 824e(a); *see, e.g.*, *FERC v. Electric Power Supply Ass'n*, 577 US 260, 277 (2016) ("If FERC sees a violation of [the just and reasonable] standard, it must take remedial action.")

[159] NOPR, 179 FERC ¶ 61,194 at P 40.

LGIP and *pro forma* LGIA are unjust, unreasonable, and unduly discriminatory or preferential and that reforms are needed to allow interconnection customers to interconnect in a reliable, efficient, transparent, and timely manner, thereby ensuring that rates, terms, and conditions for Commission-jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.[160]

ii. Comments

62. Several commenters contend that it is a rational response to a lack of pre-interconnection queue information for interconnection customers to submit multiple interconnection requests to gain information on which interconnection sites are favorable and hedge risks, which leads to withdrawals that exacerbate unmanageable interconnection queue backlogs.[161] ELCON and Environmental Defense Fund argue that the lack of sufficient information and unexpected cost escalation are the primary reasons interconnection requests are withdrawn, leading to delays and inefficiencies.[162]

63. Many commenters agree with the goal of providing additional information prior to entering the interconnection queue.[163] Some commenters state that additional

[160] *Id.* P 39.

[161] AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; Clean Energy Buyers Initial Comments at 5-6; CREA and NewSun Initial Comments at 45; Environmental Defense Fund Initial Comments at 3; ELCON Initial Comments at 3; Northwest and Intermountain Initial Comments at 5; Public Interest Organizations Initial Comments at 18.

[162] Environmental Defense Fund Initial Comments at 3; ELCON Initial Comments at 4.

[163] ACORE Reply Comments at 3; AEE Initial Comments at 9; AEP Initial

information prior to entering the interconnection queue is beneficial,[164] in particular access to information on potential network upgrades and the cost and time to interconnect.[165] Many commenters expect that potential interconnection customers' access to additional information prior to entering the interconnection queue will reduce speculative interconnection requests, thus promoting reliability and cost savings by encouraging more optimal interconnection requests that can be processed more efficiently and at lower overall cost.[166]

64. Several commenters note the importance of additional interconnection information access in light of the other reforms proposed in the NOPR. AES contends that it would

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Comments at 12; AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; APS Initial Comments at 4; Bonneville Initial Comments at 5; Clean Energy Buyers Initial Comments at 7; CREA and NewSun Initial Comments at 44; ELCON Initial Comments at 3-4; Enel Initial Comments at 9; Google Initial Comments at 15; MISO Initial Comments at 20-21; NARUC Initial Comments at 4; NESCOE Reply Comments at 2-3; NY Commission and NYSERDA Initial Comments at 6-8; NYISO Initial Comments at 16; NYTOs Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 13; PJM Initial Comments at 45; Puget Sound Initial Comments at 5; WAPA Initial Comments at 5.

[164] AEP Initial Comments at 12; APS Initial Comments at 4.

[165] EEI Reply Comments at 7-8; New Jersey Commission Initial Comments at 23; NV Energy Initial Comments at 13.

[166] Affected Interconnection Customers Initial Comments at 30; Clean Energy States Initial Comments at 3; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; ELCON Initial Comments at 3-4; Fervo Energy Initial Comments at 2-3; Google Initial Comments at 4-5; NARUC Initial Comments at 4-5; NESCOE Reply Comments at 3; New Jersey Commission Initial Comments at 20-22; New York State Department Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 13; Public Interest Organizations Initial Comments at 18; Puget Sound Initial Comments at 5; SDG&E Initial Comments at 3-4.

be inequitable for the Commission to increase security deposits to stay in the interconnection queue under the NOPR proposal to increase study and LGIA deposits without requiring transmission providers to provide sufficient information to interconnection customers.[167] Vistra asserts that the proposals to provide additional information will complement the exclusive site control proposals and provide an avenue for prospective interconnection customers to select the most viable sites on which to obtain rights and develop a location, which is a costly and time-consuming process, before entering the interconnection queue.[168] Northwest and Intermountain argue that, in order for the other proposed reforms in the NOPR to be effective, potential interconnection customers must have a solution to the problem of identifying optimal interconnection locations and configurations that is timely, cost-effective, and accurate.[169]

65. Google contends that pre-queue information is necessary because there is an extreme information asymmetry between independent power producers and transmission owners and their generating affiliates, which have greater access to planning information, including load growth, relative cost of interconnecting at different points, points of chronic congestion where upgrades might be needed, and planned local upgrades.[170] Google asserts that this information asymmetry is particularly pronounced in the non-

[167] AES Initial Comments at 13.

[168] Vistra Initial Comments at 4.

[169] Northwest and Intermountain Initial Comments at 9.

[170] Google Initial Comments at 3-4.

RTO/ISO regions, and allows transmission owners and their affiliates to identify the best locations for interconnection more quickly than independent power producers.

66. On the other hand, Dominion argues that there is no evidence in the record that a lack of information is slowing down the interconnection queue process or that transmission providers are not engaged in good faith reviews of interconnection requests.[171] According to Dominion, the Commission should focus on making the interconnection process more efficient and speedier, and the best way to achieve these goals is through the first-ready, first-served cluster study reform. While APPA-LPPC support transparency in the generator interconnection process and share the Commission's view that the availability of transmission system information should reduce the incentive to submit speculative interconnection requests, they argue that sufficient information is currently publicly available.[172]

iii. **Commission Determination**

67. We find that, absent reforms to require transmission providers to provide additional interconnection information, which can be used by interconnection customers prior to submitting an interconnection request, speculative interconnection requests will likely remain at current levels and continue to contribute to interconnection study delays and add costs to the interconnection process. Although submitting multiple interconnection requests to gain information may be a rational response to a lack of

[171] Dominion Reply Comments at 8-9.

[172] APPA-LPPC Initial Comments at 11.

pre-interconnection queue information, this practice increases interconnection study delays.[173] We also agree with commenters that additional access to interconnection information is a valuable goal[174] as it can increase the likelihood that an interconnection request is viable when submitted. We disagree with commenters that current information requirements are sufficient.[175] While certain information is currently available through the feasibility study process, as part of our reforms discussed below, we eliminate the feasibility study. Therefore, we find it necessary to provide a means for interconnection customers to obtain additional information prior to entering the interconnection queue. We concur with comments that additional access to interconnection information prior to entering the interconnection queue is important for interconnection customers to make

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[173] *See* AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; Clean Energy Buyers Initial Comments at 5-6; CREA and NewSun Initial Comments at 45; Environmental Defense Fund Initial Comments at 3; ELCON Initial Comments at 3; Northwest and Intermountain Initial Comments at 5; Public Interest Organizations Initial Comments at 18.

[174] ACORE Reply Comments at 3; AEE Initial Comments at 9; AEP Initial Comments at 12; AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; APS Initial Comments at 4; Bonneville Initial Comments at 5; Clean Energy Buyers Initial Comments at 7; CREA and NewSun Initial Comments at 44; ELCON Initial Comments at 3-4; Enel Initial Comments at 9; Google Initial Comments at 15; MISO Initial Comments at 20-21; NARUC Initial Comments at 4; NESCOE Reply Comments at 2-3; NY Commission and NYSERDA Initial Comments at 6-8; NYISO Initial Comments at 16; NYTOs Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 13; PJM Initial Comments at 45; Puget Sound Initial Comments at 5; WAPA Initial Comments at 5.

[175] APPA-LPPC Initial Comments at 9.

informed decisions, particularly given the increased requirements for interconnection customers adopted in this final rule, such as increased study deposits and site control, as discussed below.[176] We also agree that commenters raise a valid concern that an information asymmetry exists between independent power producers and transmission owner affiliates, in particular in non-RTO/ISO regions.[177]

b. Informational Interconnection Study

i. NOPR Proposal

68. In the NOPR, the Commission proposed to revise the Commission's *pro forma* LGIP to require transmission providers to offer an informational interconnection study for prospective interconnection customers.[178] The Commission proposed that the informational interconnection study would provide cost estimates for the transmission provider's interconnection facilities and network upgrade costs specific to the interconnection scenario detailed in the study agreement. The Commission also proposed to include new definitions for an informational interconnection study and informational interconnection study agreement.

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[176] AES Initial Comments at 13; Northwest and Intermountain Initial Comments at 9; Vistra Initial Comments at 4.

[177] Google Initial Comments at 3-5.

[178] NOPR, 179 FERC ¶ 61,194 at P 42.

69. Under the Commission's proposal, prospective interconnection customers could request up to five separate informational interconnection studies at a time.[179] The Commission explained that each configuration of an interconnection request would require a separate informational interconnection study. The Commission proposed that the informational interconnection study would be at the interconnection customer's expense, and each study would require a $10,000 deposit, subject to a true-up based on actual study costs.

70. The Commission proposed that, within seven business days of the receipt of a prospective interconnection customer's request for an informational interconnection study, the transmission provider would have to provide the prospective interconnection customer with an informational interconnection study agreement.[180] The Commission explained that the informational interconnection study agreement would specify the technical data that the prospective interconnection customer must provide and an estimate of the expected costs of the study, including, to the extent known by the transmission provider, an estimate of the study costs expected to be incurred by any relevant affected systems. Under the proposal, the prospective interconnection customer would have 10 business days to execute the agreement and deliver it to the transmission provider, along with the relevant technical data and study deposit, after which the transmission provider would have 45 calendar days to complete the study.

[179] *Id.* P 43.

[180] *Id.* P 44.

71. The Commission proposed that the informational interconnection study would consist of a sensitivity analysis based on the assumptions specified in the informational interconnection study agreement.[181] Under the proposal, the informational interconnection study would identify potential interconnection facilities and network upgrades that may be required to interconnect the prospective interconnection customer's proposed generating facility, including an approximation of the costs of such interconnection facilities and network upgrades. The Commission noted that the transmission provider would also coordinate with affected systems that may be impacted by the prospective interconnection customer's request to provide information on affected systems-related issues.

72. The Commission proposed an informational interconnection study agreement form, which explains that the informational interconnection study is performed solely for informational purposes and is not binding on either party.[182] The proposed agreement also requires the study report to provide specific information, including, at a minimum: (1) preliminary identification of any circuit breaker short circuit capability limits exceeded; (2) preliminary identification of any thermal overload or voltage limit violations; and (3) estimated network upgrade costs related to the identified overloads and violations.

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[181] *Id.* P 45.

[182] *Id.* P 46.

73. The Commission sought comment on: (1) whether the informational interconnection study, as proposed, would provide prospective interconnection customers with sufficient and timely information to inform decision-making prior to submitting an interconnection request; (2) whether transmission providers should be required to establish a request window of a limited number of days each year in which potential interconnection customers can request an optional informational interconnection study; and (3) the burdens on transmission providers of conducting informational studies and whether other options, such as the proposal discussed below for public interconnection information, might strike a better balance of providing interconnection customers with useful information while making efficient use of transmission provider resources.[183]

74. Additionally, the Commission proposed to add new section 3.1.2 to the *pro forma* LGIP, which provides that interconnection customers evaluating different options (such as different sizes, sites, or voltages) are encouraged but not required to use the new informational interconnection study proposed in the NOPR before entering the cluster study.[184]

ii. <u>Comments</u>

(a) <u>Comments in Support</u>

75. Several commenters support the NOPR proposal to require transmission providers to offer an informational interconnection study to prospective interconnection

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[183] *Id.* PP 47-48.

[184] *Id.* P 66.

customers.[185] Several commenters agree that the informational interconnection study proposal could reduce the number of speculative or other interconnection requests[186] and improve the efficiency of siting decisions.[187] Some commenters expect that these changes will have other benefits for the interconnection process, including cost savings from fewer and more viable interconnection requests,[188] a reduced need for project withdrawals and queue restudies,[189] and reduced burden on transmission providers, which will result in fewer interconnection study delays.[190]

76. MISO and Fervo Energy state that it is helpful for a prospective interconnection customer to compare how various MW sizes, points of interconnection, or other scenarios could affect costs, especially for prospective interconnection customers that cannot perform such analysis in house, and that the NOPR's informational interconnection study

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[185] Affected Interconnection Customers Initial Comments at 30; Clean Energy States Initial Comments at 4; Consumers Energy Initial Comments at 3; Duke Southeast Utilities Initial Comments at 6; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2; Illinois Commission Initial Comments at 6; Interwest Initial Comments at 4, 7; NESCOE Reply Comments at 2; Public Interest Organizations Initial Comments at 18; Southern Initial Comments at 28; Tesla Initial Comments at 4; Tri-State Initial Comments at 5.

[186] Fervo Energy Initial Comments at 2-3; Google Initial Comments at 4; NRECA Initial Comments at 13; NY Commission and NYSERDA Initial Comments at 6-8.

[187] Duke Southeast Utilities Initial Comments at 6-7; ISO-NE Initial Comments at 18; NARUC Initial Comments at 5; NRECA Initial Comments at 13; Pine Gate Initial Comments at 13-14; Tesla Initial Comments at 4.

[188] Evergreen Action Initial Comments at 3; NARUC Initial Comments at 5.

[189] Evergreen Action Initial Comments at 3; NRECA Initial Comments at 13.

[190] Google Initial Comments at 4.

proposal would assist in these goals.[191] Pacific Northwest Organizations argue that, without upfront interconnection cost information, independent power producers may be discouraged from entering the interconnection queue if they are subjected to higher withdrawal fees, which may result in preventing them from being considered in request for proposals (RFPs) in the Pacific Northwest.[192]

77. Some commenters stress the importance of the informational interconnection study in light of the other reforms proposed in the NOPR. For instance, Northwest and Intermountain aver that the informational study will be the primary resource for interconnection customers to demonstrate the feasibility and cost effectiveness of their interconnection plan and will serve as the foundation for subsequent negotiations for the documents that will establish commercial readiness of their project for the cluster study process.[193] Pacific Northwest Organizations assert that the NOPR's proposed commercial readiness framework would be problematic in the region without something like the informational interconnection study to discover costs before entering the queue.[194]

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[191] Fervo Energy Initial Comments at 2; MISO Initial Comments at 22.

[192] Pacific Northwest Organizations Initial Comments at 3-4.

[193] Northwest and Intermountain Initial Comments at 6-7.

[194] Pacific Northwest Organizations Initial Comments at 3.

78. Several commenters are generally supportive of the NOPR proposal but either (1) offer qualifications to that support[195] or (2) request specific changes to the proposal.[196]

(b) Comments in Opposition

79. Many commenters oppose the NOPR proposal to require transmission providers to offer an informational interconnection study to prospective interconnection customers.[197] Many commenters argue that the informational interconnection study proposal could be a

[195] Idaho Power Initial Comments at 3 (stating that it only supports the proposal if the informational interconnection study requirements are less prescriptive and allow for more flexibility); NRECA Initial Comments at 8 (stating that it does not oppose the proposal as long as the final rule includes a larger package of reforms to reduce speculative interconnection requests and speed up interconnection queues as well as affords reasonable flexibility on compliance); Ohio Commission Consumer Advocate Initial Comments at 6 (stating that informational studies should not interfere with other interconnection studies).

[196] ACE-NY Initial Comments at 10; Avangrid Initial Comments at 21; Clean Energy Buyers Initial Comments at 7; ELCON Initial Comments at 4-5; NY Commission and NYSERDA Initial Comments at 6-7; Pattern Energy Initial Comments at 20; Pine Gate Initial Comments at 11-13; Southern Initial Comments at 28.

[197] AECI Initial Comments at 3; AEP Initial Comments at 7; AEP Reply Comments at 2; APPA-LPPC Initial Comments at 3; Avangrid Initial Comments at 21; Bonneville Initial Comments at 3; CAISO Initial Comments at 5; Clean Energy Associations Initial Comments at 13; Dominion Reply Comments at 5; EEI Initial Comments at 11; EEI Reply Comments at 7-8; Enel Initial Comments at 9; ENGIE Initial Comments at 2; Eversource Initial Comments at 5; Indicated PJM TOs Initial Comments at 12; Indicated PJM TOs Reply Comments at 14; Longroad Energy Reply Comments at 3; NextEra Initial Comments at 5; NextEra Reply Comments at 8; North Dakota Commission Initial Comments at 3-4; NV Energy Initial Comments at 14; OMS Initial Comments at 5; Ørstead Initial Comments at 7; PG&E Initial Comments at 9; PJM Initial Comments at 45; PPL Initial Comments at 4; SEIA Initial Comments at 3; SPP Initial Comments at 2, 3-4; Vermont Electric and Vermont Transco Initial Comments at 3; WIRES Initial Comments at 8.

burden or divert resources,[198] which they contend would increase delays for the interconnection queue and other studies.[199] Dominion insists that the decision as to whether to offer informational interconnection studies should be the transmission

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[198] AECI Initial Comments at 3; AEE Reply Comments at 5-6; AEP Initial Comments at 7-8; AEP Reply Comments at 2; AES Initial Comments at 4; Alliant Energy Initial Comments at 4; APPA-LPPC Initial Comments at 9; APS Initial Comments at 5; Bonneville Initial Comments at 3; CAISO Initial Comments at 6; Clean Energy Buyers Initial Comments at 6; Clean Energy States Initial Comments at 4; Dominion Reply Comments at 5-6; Environmental Defense Fund Reply Comments at 5; EEI Initial Comments at 11-12; EEI Reply Comments at 8-9; ELCON Initial Comments at 4-5; Enel Initial Comments at 9; ENGIE Initial Comments at 2; Eversource Initial Comments at 5; Google Initial Comments at 5; Idaho Power Initial Comments at 3; Indicated PJM TOs Initial Comments at 12; Indicated PJM TOs Reply Comments at 14; Longroad Energy Reply Comments at 4-5; MISO Reply Comments at 17; National Grid Initial Comments at 9; NESCOE Reply Comments at 2; NextEra Reply Comments at 8-9, 11-12; New Jersey Commission Initial Comments at 21; North Dakota Commission Initial Comments at 3-4; NRECA Initial Comments at 14; NV Energy Initial Comments at 14; NYISO Initial Comments at 16; OMS Initial Comments at 5; Pine Gate Initial Comments at 12; PPL Initial Comments at 4-6; SDG&E Initial Comments at 3-4; SEIA Initial Comments at 3; SEIA Reply Comments at 4; SoCal Edison Initial Comments at 12; Tesla Initial Comments at 4; Vermont Electric and Vermont Transco Initial Comments at 3; WIRES Initial Comments at 8.

[199] AECI Initial Comments at 3; AEP Initial Comments at 7-8; AEP Reply Comments at 2-3; AES Initial Comments at 4; Alliant Energy Initial Comments at 4; APS Initial Comments at 4; Bonneville Initial Comments at 3; CAISO Initial Comments at 6; Dominion Initial Comments at 9; Duke Southeast Utilities Initial Comments at 7-8; Environmental Defense Fund Reply Comments at 5; EEI Initial Comments at 11; ELCON Initial Comments at 4-5; Eversource Initial Comments at 5-6; Google Initial Comments at 5; Idaho Power Initial Comments at 3; Indicated PJM TOs Initial Comments at 13; MISO Reply Comments at 17; National Grid Initial Comments at 7, 10-11; NESCOE Reply Comments at 2; NextEra Reply Comments at 8; New Jersey Commission Initial Comments at 21; North Dakota Commission Initial Comments at 3-4; NRECA Initial Comments at 14; NYISO Initial Comments at 16-19; OMS Initial Comments at 5; Pennsylvania Commission Initial Comments at 11; PG&E Initial Comments at 9; PG&E Reply Comments at 5; Pine Gate Initial Comments at 12; PJM Initial Comments at 45; PPL Initial Comments at 4; SEIA Initial Comments at 4; SoCal Edison Initial Comments at 12; Tesla Initial Comments at 4.

provider's and must have limits.[200] Longroad Energy states that transmission-interconnected generating facilities are typically complex facilities with unique operating characteristics which would be poorly approximated in simplified studies.[201] Environmental Defense Fund states that, while it supported the informational interconnection studies proposal in its initial comments, after review of the other comments submitted, it recommends that the Commission reconsider the proposal and ensure that any informational interconnection study reform not delay other interconnection processes.[202]

80. Several commenters contend that the informational interconnection study proposal would not likely be valuable.[203] Clean Energy Associations assert that the proposed

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[200] Dominion Reply Comments at 5.

[201] Longroad Energy Reply Comments at 7.

[202] Environmental Defense Fund Reply Comments at 5.

[203] AEE Initial Comments at 9-10; AEE Reply Comments at 5-6; AEP Initial Comments at 7; AEP Reply Comments at 2; Alliant Energy Initial Comments at 4; CAISO Initial Comments at 5-6; Clean Energy Associations Initial Comments at 14; CREA and NewSun Initial Comments at 42; Dominion Reply Comments at 5; EEI Initial Comments at 12; EEI Reply Comments at 8; Enel Initial Comments at 9; ENGIE Initial Comments at 2; Eversource Initial Comments at 5-6; Indicated PJM TOs Initial Comments at 12; Indicated PJM TOs Reply Comments at 14; ISO-NE Initial Comments at 19; Longroad Energy Reply Comments at 3; MISO Initial Comments at 20-21; MISO Reply Comments at 17-18; NextEra Initial Comments at 5, 10-11; NextEra Reply Comments at 9; North Dakota Commission Initial Comments at 4; NRECA Initial Comments at 14; NV Energy Initial Comments at 14; NYISO Initial Comments at 17; OMS Initial Comments at 5; Pacific Northwest Utilities Initial Comments at 8 n.13; PG&E Initial Comments at 9; PG&E Reply Comments at 4; PJM Initial Comments at 45; SDG&E Initial Comments at 3-4; SEIA Initial Comments at 3; SEIA Reply Comments at 3; SoCal Edison Initial Comments at 11-12; WIRES Initial Comments at 8.

informational interconnection study would provide no information related to stability-driven network upgrades, rendering it near-useless in areas where stability limits are most typically the driver of network upgrades.[204] APPA-LPPC warn that informational interconnection studies could engender controversy because prospective interconnection customers would, notwithstanding the informational nature of the studies, likely rely upon the study results in making investment decisions, even though the informational study results would inevitably diverge from the actual interconnection study results.[205]

81. Several commenters argue that the proposal is not an improvement over the status quo.[206] National Grid and NextEra assert that it is unclear how the proposal would save any time compared to the status quo, and that the best way for an interconnection customer to obtain the necessary information is by entering and proceeding through the interconnection queue with transmission providers focusing on actual studies.[207] NextEra adds that the proposed informational interconnection study is only informative in extreme cases, such as very limited capacity available on a transmission line, which the interconnection customer should be able to identify themselves.[208]

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[204] Clean Energy Associations Initial Comments at 14.

[205] APPA-LPPC Initial Comments at 12.

[206] National Grid Initial Comments at 9; New Jersey Commission Initial Comments at 21; Vermont Electric and Vermont Transco Initial Comments at 3.

[207] National Grid Initial Comments at 9; NextEra Initial Comments at 12.

[208] NextEra Initial Comments at 12.

82. CREA and NewSun express concern that the NOPR proposal places too much reliance on the usefulness of the informational interconnection study in order to justify the financial readiness and commitment NOPR proposals.[209] They assert that the informational interconnection study is not a useful replacement for the feasibility study, which takes into account the impact of other interconnection customers in the interconnection queue cluster. Therefore, CREA and NewSun ask the Commission to instead retain the feasibility study as part of the cluster study process to allow interconnection customers to obtain cluster-level information on likely costs and network upgrades before proceeding further with major deposits and irretrievable commitments.

83. Several commenters point to the experience with similar studies in SPP and MISO as evidence that the optional informational interconnection study proposal will be little-used in practice.[210] SPP reports that its interconnection customers explained that their time could be more effectively spent working on the more definitive system impact studies, that the feasibility and preliminary impact studies did not provide results that

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[209] CREA and NewSun Initial Comments at 46-47.

[210] AEE Initial Comments at 10; AEP Initial Comments at 8,12; Clean Energy Associations Initial Comments at 14; Enel Initial Comments at 9-10; Longroad Energy Reply Comments at 3-4; MISO Initial Comments at 21; NextEra Reply Comments at 8; Omaha Public Power Initial Comments at 3; SEIA Reply Comments at 3; SPP Initial Comments at 3. NextEra argues that transmission providers with large numbers of interconnection requests have tried optional interconnection studies and have not found them to be useful. NextEra Reply Comments at 10.

could be relied on in making business decisions, and that this same outcome would be true of the proposed informational interconnection study.[211]

84. Several commenters point to the inability of the informational interconnection studies to provide reliable cost estimates[212] and believe that the information provided in these studies will be quickly outdated.[213] The New Jersey Commission is concerned that this approach may not materially reduce the uncertainty interconnection customers currently face.[214] In particular, many commenters contend that the informational interconnection study is not meaningful in the context of a cluster interconnection process.[215] Commenters argue that, because the informational interconnection study does not provide information on other interconnection customers that would enter the

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[211] SPP Initial Comments at 3.

[212] AEP Initial Comments at 8; Ameren Initial Comments at 5; CAISO Initial Comments at 5; Clean Energy Associations Initial Comments at 14; CREA and NewSun Initial Comments at 43; Cyprus Creek Initial Comments at 13; Enel Initial Comments at 9; Interwest Initial Comments at 7-8; NextEra Initial Comments at 5; NRECA Initial Comments at 14; PJM Initial Comments at 45; SoCal Edison Initial Comments at 11-12.

[213] AEP Initial Comments at 8; Alliant Energy Initial Comments at 4; Dominion Initial Comments at 10; Enel Initial Comments at 9; Eversource Initial Comments at 9; Interwest Initial Comments at 7-8; PJM Initial Comments at 45; PJM TOs Initial Comments at 13; SEIA Reply Comments at 4.

[214] New Jersey Commission Initial Comments at 21.

[215] *Id.*; AEE Initial Comments at 9-10; Avangrid Initial Comments at 23-24; Clean Energy Associations Initial Comments at 14; CREA and NewSun Initial Comments at 43; Dominion Reply Comments at 6; EEI Initial Comments at 12; EEI Reply Comments at 8; Enel Initial Comments at 9; Eversource Initial Comments at 9-10; ISO-NE Initial Comments at 18-19; MISO Initial Comments at 21; NRECA Initial Comments at 14; NV Energy Initial Comments at 14; PJM Initial Comments at 45; PPL Initial Comments at 5; SEIA Initial Comments at 4-5; SEIA Reply Comments at 3-4; SoCal Edison Initial

interconnection queue at the same time, there is no guarantee that the study results will even approximate the actual network upgrade costs determined by the cluster results.[216]

85. Some commenters expect the proposal will work against the Commission's goal of faster interconnection queue processing.[217] Some commenters state that any reduction in speculative interconnection requests will be offset by an increase in speculative informational interconnection requests, which would require transmission providers to shift their focus from the actual interconnection queue to this more burdensome informational interconnection process, which is outside of their interconnection study process.[218] NRECA states that, if the proposal is included in the final rule, the

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Comments at 12; SPP Initial Comments at 2-3.

[216] AEE Initial Comments at 9-10; CAISO Initial Comments at 5-6; CREA and NewSun Initial Comments at 44; Dominion Initial Comments at 10; Duke Southeast Utilities Initial Comments at 7; EEI Reply Comments at 8; Indicated PJM TOs Initial Comments at 13; ISO-NE Initial Comments at 18-19; MISO Initial Comments at 22; NextEra Initial Comments at 11-12; New Jersey Commission Initial Comments at 21; PG&E Reply Comments at 5; PPL Initial Comments at 5; SEIA Reply Comments at 3-4; SoCal Edison Initial Comments at 12.

[217] AEE Reply Comments at 6; AEP Initial Comments at 11; Avangrid Initial Comments at 22-23; CAISO Initial Comments at 6; Dominion Reply Comments at 6-7; National Grid Initial Comments at 7; NESCOE Reply Comments at 2; NV Energy Initial Comments at 14; Pennsylvania Commission Initial Comments at 11-12.

[218] AECI Initial Comments at 4; AEP Initial Comments at 11; APPA-LPPC Initial Comments at 11-12; Bonneville Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,194 at PP 20, 22, 166); Clean Energy Buyers Initial Comments at 6; Dominion Reply Comments at 6; NextEra Initial Comments at 12; NYISO Initial Comments at 17; Pennsylvania Commission Initial Comments at 11 (explaining that because the informational study is not binding on any party, the study does not move projects through the interconnection queue).

Commission should ensure that it is limited and is not expanded into an elaborate serial study process prior to the cluster study process.[219] Avangrid notes that some transmission providers have recently eliminated interconnection studies to reduce interconnection queue processing time.[220] Pennsylvania Commission asserts that the Commission should assess the results of the NOPR's proposed reforms before requiring any new study processes that may further slow the interconnection queue process.[221]

86. Several commenters note the challenge of staffing to fulfill the informational interconnection study requirements given the limited number of qualified planners and engineers.[222]

87. Several commenters urge the Commission to weigh the benefits against the burdens to determine whether to adopt the informational interconnection study proposal.[223] WAPA states that, while it agrees that it is important to provide prospective interconnection customers with additional information, it has concerns about the

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[219] NRECA Initial Comments at 14.

[220] Avangrid Initial Comments at 23 (citing NOPR, 179 FERC ¶ 61,194 at P 56 n.111).

[221] Pennsylvania Commission Initial Comments at 11-12.

[222] *Id.* at 11; AEP Initial Comments at 10-11; APPA-LPPC Initial Comments at 12; Avangrid Initial Comments at 22-23; Bonneville Initial Comments at 5; Eversource Initial Comments at 5-6; Indicated PJM TOs Initial Comments at 12; Indicated PJM TOs Reply Comments at 14; LADWP Initial Comments at 2; OMS Initial Comments at 5.

[223] Ameren Initial Comments at 5; R Street Initial Comments at 9; Xcel Initial Comments at 20.

proposed timelines and penalties, the potential amount of informational interconnection study requests it could receive, and its ability to process up to five simultaneous informational interconnection study requests per interconnection customer.[224] According to Vermont Electric and Vermont Transco, even if the informational interconnection studies envisioned by the NOPR provide interconnection customer benefits, the burdens of providing informational interconnection studies with cost estimates under the NOPR's short proposed time frames and low deposit amounts would be considerable especially for smaller companies such as Vermont Electric and Vermont Transco.[225] Other commenters contend that the informational interconnection study proposal has insufficient benefits.[226]

88. Given PJM's opposition to the informational interconnect study, it recommends modifying the proposed new section 3.1.2 to the *pro forma* LGIP to encourage, but not require, interconnection customers evaluating different project characteristics to use a prescreening tool, such as the queue scope tool PJM is developing, prior to submitting an interconnection request.[227]

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[224] WAPA Initial Comments at 4-5.

[225] Vermont Electric and Vermont Transco Initial Comments at 3.

[226] *Id.*; AEP Initial Comments at 7; AES Initial Comments at 4; EEI Initial Comments at 11; ENGIE Initial Comments at 2; NextEra Initial Comments at 10-11; Ørstead Initial Comments at 7; PJM Initial Comments at 45; SEIA Initial Comments at 3.

[227] PJM Initial Comments at 19 (explaining that the queue scope is an interactive prescreening tool that will allow interconnection customers to screen potential points of interconnection and assess grid capacity (head room) based on a given amount of MW injection or withdrawal at a given point of interconnection and that the tool will be

iii. **Commission Determination**

89. We decline to adopt the NOPR proposal to modify the *pro forma* LGIP to require transmission providers to offer an informational interconnection study for prospective interconnection customers. We are persuaded by commenters' concerns that requiring an informational interconnection study could divert the transmission provider's resources away from the cluster studies we require in this final rule and undermine the benefits of those reforms that seek to reduce interconnection study delays, costs, and burden on constrained engineering labor. Moreover, we agree with commenters that highlight the various limitations of an informational interconnection study. Notably, an informational interconnection study, as proposed in the NOPR, would have provided a serial, snapshot-in-time analysis on the impact of a single interconnection request, but, in the context of the subsequent cluster study, the actual impact of an interconnection request within a larger cluster would reflect different assumptions and differ from the informational interconnection study, providing minimal or no value to interconnection customers. The cost estimates that result from such an informational interconnection study would bear little correspondence to costs determined during a cluster study process and thus provide minimal value to interconnection customers.

90. We also find persuasive comments that the informational interconnection study requirement proposed in the NOPR is not the most effective way to provide

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available at no charge). PJM's proposed section 3.1.2 of the *pro forma* LGIP would read: "Interconnection Customers evaluating different options . . . to use the prescreening tool (Section 6.1 of this LGIP) before entering the Cluster Study."

interconnection customers with the needed pre-interconnection queue information. At the same time, we continue to believe that there is a lack of information available to prospective interconnection customers prior to entering the interconnection queue, especially given other interconnection customer-related reforms adopted in this final rule.[228] Therefore, as discussed below, we adopt the NOPR proposal to set minimum requirements for transmission providers to publicly post available information pertaining to generator interconnection.[229] We find that the posting of this information provides a better balance between the benefits of additional information for prospective interconnection customers and the burdens on transmission providers.

91. In response to commenters that support the informational interconnection study NOPR proposal, below we explain how several of the NOPR proposals that we adopt in this final rule address their specific concerns. To address commenters' concerns with the number of speculative interconnection requests,[230] we adopt more stringent site control requirements and increased commercial readiness deposit requirements,[231] which we believe will better address these concerns than the informational interconnection study proposal. Additionally, we find that the minimum requirements for transmission

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[228] *See* Northwest and Intermountain Initial Comments at 6-7.

[229] *See infra* Section III.A.1.c.iii.

[230] Fervo Energy Initial Comments at 2-3; Google Initial Comments at 4; NRECA Initial Comments at 13; NY Commission and NYSERDA Initial Comments at 6-8.

[231] *See infra* Sections III.A.6.b.iii, III.A.6.c.iii.

providers to publicly post available information pertaining to generator interconnection[232] and the existing requirements in section 2.3 of the *pro forma* LGIP for transmission providers to post up-to-date base case study models on their Open Access Same-time Information System (OASIS) or other password-protected websites will improve the efficiency of siting decisions[233] and will provide interconnection customers with information about the feasibility of their interconnection plans.[234]

92. We are not persuaded that the informational interconnection study proposal would benefit the interconnection process through: (1) cost savings from fewer, more feasible interconnection requests;[235] (2) a reduced need for interconnection request withdrawals and restudies;[236] and (3) accurate upfront interconnection cost information.[237] On the contrary, the Commission's adoption of the cluster study reforms in this final rule[238] means that the serial nature of the informational interconnection study would fail to

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[232] *See infra* Section III.A.1.c.iii.

[233] Duke Southeast Utilities Initial Comments at 6-7; ISO-NE Initial Comments at 18; NARUC Initial Comments at 5; NRECA Initial Comments at 13; Pine Gate Initial Comments at 13-14; Tesla Initial Comments at 4.

[234] Northwest and Intermountain Initial Comments at 6-7; Pacific Northwest Organizations Initial Comments at 3.

[235] Evergreen Action Initial Comments at 3; NARUC Initial Comments at 5.

[236] Evergreen Action Initial Comments at 3; NRECA Initial Comments at 13.

[237] Fervo Energy Initial Comments at 2; MISO Initial Comments at 22; Pacific Northwest Organizations Initial Comments at 3-4.

[238] *See infra* Section III.A.2.

reflect the outcome of the cluster study, and thus would provide minimal, if any, benefits to interconnection customers.[239] We also no longer believe that adopting the informational interconnection study proposal would reduce burdens on transmission providers.[240] This is because the record overwhelmingly demonstrates that the proposal would result in additional burdens on transmission providers and would likely cause transmission providers to divert resources from their cluster study process to conduct informational interconnection studies,[241] thus increasing study delays and costs. Similarly, we decline CREA and NewSun's request that the Commission retain the

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[239] *See* AEE Initial Comments at 9-10; Avangrid Initial Comments at 23-24; Clean Energy Associations Initial Comments at 14; CREA and NewSun Initial Comments at 43; Dominion Reply Comments at 6; EEI Initial Comments at 12; EEI Reply Comments at 8; Enel Initial Comments at 9; Eversource Initial Comments at 9-10; ISO-NE Initial Comments at 18-19; MISO Initial Comments at 21; New Jersey Commission Initial Comments at 21; NRECA Initial Comments at 14; NV Energy Initial Comments at 14; PJM Initial Comments at 45; PPL Initial Comments at 5; SEIA Initial Comments at 4-5; SEIA Reply Comments at 3-4; SoCal Edison Initial Comments at 12; SPP Initial Comments at 2-3.

[240] *See* Google Initial Comments at 5 (arguing that the informational interconnection study requirement alone would likely increase the burden on transmission providers in a way that would lengthen delays).

[241] *Id.*; AECI Initial Comments at 3; AEE Reply Comments at 5-6; AEP Initial Comments at 7-8; AEP Reply Comments at 2; AES Initial Comments at 4; Alliant Energy Initial Comments at 4; APPA-LPPC Initial Comments at 9; APS Initial Comments at 5; Bonneville Initial Comments at 3; CAISO Initial Comments at 6; Clean Energy Buyers Initial Comments at 6; Clean Energy States Initial Comments at 4; Dominion Reply Comments at 5-6; Environmental Defense Fund Reply Comments at 5; EEI Initial Comments at 11-12; EEI Reply Comments at 8-9; ELCON Initial Comments at 4-5; Enel Initial Comments at 9; ENGIE Initial Comments at 2; Eversource Initial Comments at 5; Idaho Power Initial Comments at 3; Indicated PJM TOs Initial Comments at 12; Indicated PJM TOs Reply Comments at 14; Longroad Energy Reply Comments at 4-5; MISO Reply Comments at 17; National Grid Initial Comments at 9; NESCOE Reply Comments at 2; New Jersey Commission Initial Comments at 21;

feasibility study instead of the informational interconnection study. As we discuss below, the feasibility study was required for the serial study process but is no longer relevant for the cluster study process.[242] We believe that our requirement for transmission providers to publicly post certain interconnection information will provide interconnection customers with the information they need prior to entering the interconnection queue, and therefore decline to adopt CREA and NewSun's request to maintain the feasibility study.

93. Because we do not adopt the NOPR proposal to require transmission providers to offer an informational interconnection study, we decline to adopt the proposal to add new section 3.1.2 to the *pro forma* LGIP to encourage interconnection customers to use the informational interconnection study.

c. **Public Interconnection Information**

i. **NOPR Proposal**

94. In the NOPR, the Commission proposed to require transmission providers to maintain and make publicly available an interactive visual representation of available interconnection capacity (commonly known as a "heatmap") as well as a table of relevant interconnection metrics that allow prospective interconnection customers to see certain

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NextEra Reply Comments at 8-9, 11-12; North Dakota Commission Initial Comments at 3-4; NRECA Initial Comments at 14; NV Energy Initial Comments at 14; NYISO Initial Comments at 16; OMS Initial Comments at 5; Pine Gate Initial Comments at 12; PPL Initial Comments at 4-6; SDG&E Initial Comments at 3-4; SEIA Initial Comments at 3; SEIA Reply Comments at 4; SoCal Edison Initial Comments at 12; Tesla Initial Comments at 4; Vermont Electric and Vermont Transco Initial Comments at 3; WIRES Initial Comments at 8.

[242] *See infra* Section III.A.2.f.iii.

estimates of a potential generating facility's effect on the transmission provider's transmission system.[243] Specifically, the Commission proposed to revise section 6.4 of the *pro forma* LGIP to require transmission providers to post on their public website a heatmap of estimated incremental injection capacity (in MW) available at each bus in the transmission provider's footprint under N-1 conditions, as well as provide a table of results showing the estimated impact of the addition of a proposed project (based on the user-specified MW amount, voltage level, and point of interconnection) for each monitored facility impacted by the proposed project on: (1) the distribution factor; (2) the MW impact (based on the proposed project size and the distribution factor); (3) the percentage impact on the monitored facility (based on the MW values of the proposed project and the monitored facility rating); (4) the percentage of power flow on the monitored facility before the proposed project; and (5) the percentage power flow on the monitored facility after the injection of the proposed project. The Commission explained that these metrics would be calculated based on the power flow model of the cluster study or restudy with the transfer simulated from each bus to the whole transmission provider's footprint (to approximate Network Resource Interconnection Service (NRIS)), and with the incremental capacity at each bus decremented by the existing and queued generation in the cluster (based on the existing or requested interconnection service limit of the generation). The Commission proposed to require transmission providers to update this information within 30 days after the completion of each cluster study and restudy.

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[243] NOPR, 179 FERC ¶ 61,194 at P 51.

95. The Commission sought comment on whether: (1) there are any security concerns with this proposed requirement; and (2) the assumptions specified for the analysis are the right set of assumptions.[244]

ii. Comments

(a) Comments in Support

96. Many commenters express support for the NOPR's proposal to require transmission providers to provide public interconnection information.[245] Several commenters agree that the NOPR proposal will provide valuable information to interconnection customers before they enter the interconnection queue.[246] Several

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[244] *Id.* P 52.

[245] ACE-NY Initial Comments at 11; AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; APPA-LPPC Initial Comments at 13; CAISO Initial Comments at 7; CESA Initial Comments at 7; Clean Energy Associations Initial Comments at 12; Clean Energy Buyers Initial Comments at 6-7; Colorado Commission Initial Comments at 8; Consumers Energy Initial Comments at 3; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; Environmental Defense Fund Reply Comments at 2-3; ELCON Initial Comments at 4; ENGIE Initial Comments at 2; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2; Google Initial Comments at 14; Google Reply Comments at 6; Illinois Commission Initial Comments at 6; Interwest Initial Comments at 7; New Jersey Commission Initial Comments at 11-12; Northwest and Intermountain Initial Comments at 9-10; NY Commission and NYSERDA Initial Comments at 8; Ørsted Initial Comments at 7; Pattern Energy Initial Comments at 23; Pine Gate Initial Comments at 13; Public Interest Organizations Initial Comments at 18-19; R Street Initial Comments at 8, 10; Southern Initial Comments at 28; Tesla Initial Comments at 6-7; Vistra Initial Comments at 1, 4.

[246] Alliant Energy Initial Comments at 5; Clean Energy Associations Initial Comments at 12; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; EEI Initial Comments at 12-13; ELCON Initial Comments at 6; ENGIE Initial Comments at 2; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2-3; Illinois Commission Initial Comments at 6;

commenters aver that the proposal could reduce the number of interconnection requests withdrawn[247] and therefore could reduce costs for all parties.[248] Alliant Energy and Clean Energy Associations also see value in the standardized format of the proposed public interconnection information.[249] R Street states that a properly done visual representation of interconnection capacity can be a "powerful decentralized self-screening tool."[250] R Street states that better information and simpler deliverability requirements shift congestion performance risk to generating facilities while reducing barriers to entry.[251] The Ohio Commission Consumer Advocate states that the visual map of available interconnection capacity would be useful both to transmission providers and

Indicated PJM TOs Initial Comments at 14; Indicated PJM TOs Reply Comments 6; ISO-NE Initial Comments at 26-27; New Jersey Commission Initial Comments at 12; NY Commission and NYSERDA Initial Comments at 8; Ohio Commission Consumer Advocate Initial Comments at 7; Pacific Northwest Utilities Initial Comments at 13; SEIA Initial Comments at 5.

[247] CESA Initial Comments at 9; CESA Reply Comments at 3; Consumers Energy Initial Comments at 3; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; EEI Initial Comments at 12-13; ELCON Initial Comments at 6; Evergreen Action Initial Comments at 3; Google Initial Comments at 14; Illinois Commission Initial Comments at 6-7; New Jersey Commission Initial Comments at 12; NY Commission and NYSERDA Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 13; SEIA Initial Comments at 5.

[248] Evergreen Action Initial Comments at 3; New Jersey Commission Initial Comments at 12.

[249] Alliant Energy Initial Comments at 5; Clean Energy Associations Initial Comments at 12.

[250] R Street Initial Comments at 10.

[251] R Street Reply Comments at 2.

interconnection customers and would encourage information sharing on transmission system congestion during the interconnection process.[252] Google argues that making these data publicly available to consumers would allow buyers to make informed choices regarding power procurement.[253] Additionally, Google asserts that there needs to be a standard of reasonable care applied to ensure that the publicly available information is reasonably current and useful to avoid exploratory interconnection requests.[254] SEIA argues that greater transparency will increase competition between merchant and utility developed generating facilities, benefiting consumers.[255] Illinois Commission contends that, if properly implemented, the NOPR proposal will increase the pace at which new generating facilities can connect to the transmission system, furthering state policy objectives.[256]

97. Some commenters contend that the proposal to provide public interconnection information is not overly burdensome.[257] APPA-LPPC members report that the information posting and interactive capability described in the NOPR could be feasibly

[252] Ohio Commission Consumer Advocate Initial Comments at 7.

[253] Google Initial Comments at 4.

[254] Google Reply Comments at 7.

[255] SEIA Reply Comments at 5.

[256] Illinois Commission Initial Comments at 6.

[257] APPA-LPPC Initial Comments at 16; Clean Energy Associations Initial Comments at 12-13; Google Initial Comments at 14; New York State Department Initial Comments at 8; Pennsylvania Commission Initial Comments at 13; SEIA Initial Comments at 6.

implemented with available industry system simulation tools.[258] Clean Energy Associations state that heatmaps should be as automated as possible, without significant commitments of staff or resources.[259]

98. Several commenters point to the fact that some transmission providers are already developing such tools as evidence that these tools are unlikely to cause further delays to stressed interconnection queues or additional burden on transmission providers.[260] For instance, some commenters note that MISO already offers a heatmap that represents geographically advantageous siting locations.[261] Several commenters also note that PJM is developing such a tool.[262] PJM states that in 2023 its queue scope tool will provide a congestion map with colors or symbols indicating the worst flowgate loading at each point of interconnection.[263] SPP states that it is also developing a tool to be implemented

[258] APPA-LPPC Initial Comments at 16.

[259] Clean Energy Associations Initial Comments at 13.

[260] *Id.* at 12; Environmental Defense Fund Reply Comments at 3; ENGIE Initial Comments at 2-3; Pennsylvania Commission Initial Comments at 13.

[261] CESA Reply Comments at 5; Fervo Energy Reply Comments at 3; OMS Initial Comments at 3, 6; R Street Initial Comments at 10; SEIA Initial Comments at 6.

[262] CESA Reply Comments at 4; Fervo Energy Reply Comments at 3; Indicated PJM TOs Initial Comments at 14; Ohio Commission Consumer Advocate Initial Comments at 7; Pennsylvania Commission Initial Comments at 13; PJM Initial Comments at 48; PPL Initial Comments at 9; R Street Initial Comments at 10; SEIA Initial Comments at 6.

[263] PJM Initial Comments at 46-47.

by 2025 that would provide much of the functionality described in the Commission's public information proposal to new interconnections.[264]

99. Several commenters contend that the public information proposal is a more reasonable balance of costs and benefits relative to the informational interconnection study proposal.[265] Pennsylvania Commission states that, once a public information tool is established, it may require fewer ongoing resources, continuing to inform interconnection customers while freeing those resources for additional interconnection studies as compared to the proposed informational interconnection study.[266]

(b) <u>Comments in Opposition</u>

100. A few commenters oppose the NOPR proposal to require transmission providers to provide public interconnection information.[267] A larger number of commenters express reservations about the proposal,[268] in particular regarding its usefulness[269] or the

[264] SPP Initial Comments at 4.

[265] Ameren Initial Comments at 5; APPA-LPPC Initial Comments at 16; APS Initial Comments at 5; Bonneville Initial Comments at 5; Pennsylvania Commission Initial Comments at 13; PJM Initial Comments at 45-48; R Street Initial Comments at 10.

[266] Pennsylvania Commission Initial Comments at 13.

[267] Avangrid Reply Comments at 4; El Paso Electric Initial Comments at 8; PG&E Initial Comments at 9.

[268] AEP Initial Comments at 13; Idaho Power Initial Comments at 3; NextEra Initial Comments at 12-13; Omaha Public Power Initial Comments at 4; PacifiCorp Initial Comments at 13-14; SPP Initial Comments at 4; Tri-State Initial Comments at 4; WAPA Initial Comments at 7-8.

[269] AEP Initial Comments at 13; Idaho Power Initial Comments at 3; ISO-NE Initial Comments at 17; Longroad Energy Reply Comments at 7; Omaha Public Power

burden it creates.[270] Other commenters request that the Commission make public interconnection information posting optional.[271]

101. Several commenters argue that the proposal to require transmission providers to provide public interconnection information is not useful,[272] particularly because it might not provide sufficient detail[273] or commercially actionable information for interconnection customers.[274] Commenters explain that heatmaps are specific to a moment in time and thus not representative of actual available injection across the transmission system, which is ever-changing.[275] NextEra observes that heatmaps do not contain actionable information for interconnection and instead focus on energy prices and

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Initial Comments at 4; PacifiCorp Initial Comments at 13-14; SPP Initial Comments at 4; WAPA Initial Comments at 7-8.

[270] AECI Initial Comments at 5; Dominion Initial Comments at 12; National Grid Initial Comments at 7; NextEra Initial Comments at 12-13; Omaha Public Power Initial Comments at 4; PacifiCorp Initial Comments at 13-14; SPP Initial Comments at 4.

[271] AEP Initial Comments at 13; Avangrid Initial Comments at 21-22; SPP Initial Comments at 4.

[272] Dominion Initial Comments at 13; Idaho Power Initial Comments at 3; ISO-NE Initial Comments at 17; NextEra Initial Comments at 12; New York State Department Initial Comments at 8; NYISO Initial Comments at 17; Omaha Public Power Initial Comments at 4; PacifiCorp Initial Comments at 14.

[273] AECI Initial Comments at 5; Dominion Initial Comments at 13; Longroad Energy Reply Comments at 7; National Grid Initial Comments at 8; New York State Department Initial Comments at 8; Omaha Public Power Initial Comments at 4.

[274] AEE Initial Comments at 9; Cypress Creek Initial Comments at 13; NextEra Initial Comments at 12.

[275] AECI Initial Comments at 5; AEP Initial Comments at 13; New York State Department Initial Comments at 8; NYISO Initial Comments at 17.

congestion.[276] ISO-NE, MISO, and Omaha Public Power note that a visual representation of interconnection capacity cannot account for all of the conditions identified in a system impact study, including different system stresses, operability issues (e.g., N-1-1), stability and voltage issues, and weak transmission system issues.[277] Longroad Energy asserts that generator interconnection heatmaps or hosting capacity maps can be of some use for interconnections to the distribution system but are unlikely to be beneficial for projects interconnecting at transmission voltages.[278]

102. Some commenters do not believe that the heatmap proposal will appreciably reduce speculative interconnection requests.[279] MISO explains that, in its experience, few interconnection customers use its interconnection heatmap tool and instead tend to use their own tools.[280] Puget Sound states that, even with a heatmap, if an interconnection customer has a request that would require energy transfer across balancing authorities, it would have to submit an interconnection request to get information on the scope of necessary network upgrades.[281] NV Energy asserts that a heatmap of its transmission system would be of little value, appearing as though there is

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[276] NextEra Initial Comments at 12.

[277] ISO-NE Initial Comments at 17; MISO Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,194 at P 50 & n.105); Omaha Public Power Initial Comments at 4.

[278] Longroad Energy Reply Comments at 7.

[279] Idaho Power Initial Comments at 3; PPL Initial Comments at 9.

[280] MISO Initial Comments at 25-26.

[281] Puget Sound Initial Comments at 6.

no available transfer capacity, because the generation in its interconnection queue is more than five times the level of NV Energy load.[282] Meanwhile, Puget Sound states that a heatmap of its territory would only account for generation and interconnection capacity in its balancing authority footprint even though its transmission goes beyond this footprint.[283]

103. Several commenters contend that a heatmap tool as proposed would be less useful in a cluster study than it is in a serial process because it cannot include similarly queued generation.[284] Ohio Commission Consumer Advocate questions whether it will capture the "dynamic elements" of cluster studies and restudies.[285] PacifiCorp and AEP state that the mere fact that an area is not shown as congested on a heatmap does not mean that it will be a suitable interconnection location, particularly if multiple interconnection customers seek to interconnect there.[286]

104. Longroad Energy and PacifiCorp express concern that the heatmap tools would not be restricted to prospective interconnection customers and could instead be used by

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[282] NV Energy Initial Comments at 10.

[283] Puget Sound Initial Comments at 6.

[284] CAISO Initial Comments at 8; CREA and NewSun Initial Comments at 48; Duke Southeast Utilities Initial Comments at 6-7; MISO Initial Comments at 26; Ohio Commission Consumer Advocate Initial Comments at 7; PacifiCorp Initial Comments at 15.

[285] Ohio Commission Consumer Advocate Initial Comments at 7.

[286] AEP Initial Comments at 13; PacifiCorp Initial Comments at 15.

third-party consultants for their own business interests; for instance, real estate speculators could use the information to secure exclusive site control for locations that show significant generator interconnection capacity.[287] According to Longroad Energy, such risk is particularly harmful to wind and solar generation interconnection customers' needs for large tracts of land to accommodate their generation equipment.[288]

105. Some commenters assert that maintaining the heatmap and posting required information on available interconnection capacity would be burdensome for transmission providers, especially in non-RTO/ISO regions.[289] Similarly, NV Energy states that it participates in the CAISO energy imbalance market and its energy management system does not currently have the technical functionality to build an interactive map that shows information like the available interconnection capacity.[290] Some commenters argue that the heatmaps may provide insufficient benefit to justify cost, resources, and time it would take to produce them.[291] Omaha Public Power further asserts that interconnection

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[287] Longroad Energy Reply Comments at 7; PacifiCorp Initial Comments at 15.

[288] Longroad Energy Reply Comments at 7.

[289] National Grid Initial Comments at 7-8; PacifiCorp Initial Comments at 13; Tri-State Initial Comments at 7.

[290] NV Energy Initial Comments at 10.

[291] Dominion Initial Comments at 13; National Grid Initial Comments at 8; NextEra Initial Comments at 12; New York State Department Initial Comments at 8; Omaha Public Power Initial Comments at 4; Pacific Northwest Utilities Initial Comments at 14; PPL Initial Comments at 9; Tri-State Initial Comments at 4; WAPA Initial Comments at 7.

customers will likely find it more valuable for a transmission provider invest in more reliable and consequential studies.[292] Pacific Northwest Utilities assert that the Commission should present additional data regarding the benefits of requiring a heatmap before mandating their use.[293] Clean Energy Associations recommend that the Commission consider other means of increasing information to prospective interconnection customers, such as public scoping meetings prior to the prospective interconnection customers entering the interconnection queue.[294]

106. Some commenters express concern that the public information proposal will impose new costs on ratepayers and market participants.[295] WAPA states that, given its defined appropriations and budgets, it is difficult to create new programs, unlike for larger investor-owned utilities or RTOs/ISOs.[296] Dominion estimates that implementation would require a large up-front financial commitment, potentially for third-party software and personnel hours, and longer-term financial commitment to maintain such a site.[297]

[292] Omaha Public Power Initial Comments at 4.

[293] Pacific Northwest Utilities Initial Comments at 14.

[294] Clean Energy Associations Initial Comments at 14.

[295] New York State Department Initial Comments at 8; SoCal Edison Initial Comments at 13.

[296] WAPA Initial Comments at 7.

[297] Dominion Initial Comments at 12.

NV Energy contends that creating such a heatmap showing interconnection capabilities would require finding an eligible software, an ongoing expense.[298]

107. Several commenters speak to the burden of additional staffing needs to provide public interconnection information. National Grid states that the interactive visual representation tool, even if contracted from a third party, would require significant time commitments from numerous personnel with relevant and advanced expertise in transmission and interconnection engineering.[299] Tri-State notes that the Commission has recognized the lack of available engineers and that imposing a heatmap requirement would exacerbate the problem.[300] Dominion and Duke Southeast Utilities state that any additional process would require additional financial and personnel resources, and also burden the same personnel that are already engaged in managing the interconnection queue.[301] El Paso Electric argues that transmission providers should not be required to allocate human resources from interconnection studies to monthly transmission line capacity estimates because the staff reallocation could cause interconnection study backlogs.[302] PacifiCorp states that this burden will be particularly onerous to

[298] NV Energy Initial Comments at 10.

[299] National Grid Initial Comments at 7-8.

[300] Tri-State Initial Comments at 8.

[301] Dominion Initial Comments at 13; Duke Southeast Utilities Initial Comments at 7.

[302] El Paso Electric Initial Comments at 7.

transmission providers outside RTO/ISO regions, which have comparatively few transmission staff available.[303]

108. Several commenters suggest that interconnection customers, on their own or with consultants, can perform studies with the available information that would provide estimates on available capacity similar to that produced under the NOPR proposal.[304] PPL states that interconnection customers can make their own such maps using transmission planning models the Commission makes available following a Freedom of Information Act request.[305] APPA-LPPC argue that the Commission fails to establish that the information already available to prospective interconnection customers under the existing *pro forma* LGIP, along with the substantial supplement implemented with Order No. 845, is inadequate.[306] SoCal Edison states that the information included in the NOPR proposal and more is already available if interconnection customers request it from the Commission for their own studies or use studies developed by transmission providers.[307] The Ohio Commission Consumer Advocate states that the determination of a suitable site

[303] PacifiCorp Initial Comments at 13.

[304] *Id.* at 15; AEP Initial Comments at 8; APPA-LPPC Initial Comments at 9; El Paso Electric Initial Comments at 7; PPL Initial Comments at 9; SoCal Edison Initial Comments at 14.

[305] PPL Initial Comments at 9.

[306] APPA-LPPC Initial Comments at 9.

[307] SoCal Edison Initial Comments at 14.

depends largely on the location and geography of the resources, which is publicly available from national labs and the U.S. Energy Information Administration.[308]

109. Several commenters state that sufficient data are already required to be posted on OASIS.[309] According to Idaho Power, Order No. 2003-A required interconnection study reports to be publicly available and provide locational and cost information for previously studied interconnections, but this has not reduced the amount of interconnection requests at congested locations.[310] SoCal Edison and NYISO state that this information is already available in FERC Form 715, where it is protected with a non-disclosure agreement as critical energy infrastructure information (CEII) and has the benefit of being available in one centralized location.[311] On the other hand, ACE-NY disagrees with the assertion that FERC Form 715 provides sufficient information for interconnection customers to do their own analysis, asserting that the FERC Form 715 database base cases do not contain sufficient data about the generation interconnection queue and study assumptions and are therefore inadequate.[312] Rather, ACE-NY argues that more detailed base cases such as those currently being made available by MISO and PJM, should be required.

[308] Ohio Commission Consumer Advocate Initial Comments at 6-7.

[309] Duke Southeast Utilities Initial Comments at 6-7; Idaho Power Initial Comments at 3; NV Energy Initial Comments at 10; PacifiCorp Initial Comments at 14-15.

[310] Idaho Power Initial Comments at 3.

[311] NYISO Initial Comments at 17; SoCal Edison Initial Comments at 14.

[312] ACE-NY Reply Comments at 3-4.

110. Several commenters state that the usefulness of public interconnection information proposal will depend on the implementation details.[313] For example, Illinois Commission and CESA recognize that the accuracy of the heatmaps is an important part of how useful they will be.[314] Puget Sound states that it has considered creating such a heatmap but has concerns about its effectiveness given implementation challenges.[315] SPP states that technology, information, and tools are quickly evolving and that a standardization tool might be obsolete before it is implemented.[316] CESA explains that currently CAISO provides static, snapshot-in-time transmission capability estimates that are helpful but do not capture locational granularity or other projects already in the interconnection queue, making it difficult to make an informed project siting decision and at times requiring data requests of CAISO.[317] For this reason, CESA stresses that the heatmaps and associated data must be made available in a user-friendly format. CREA and NewSun argue that the Commission should be careful not to overestimate the ability to forecast interconnection costs and project viability that will ultimately result from a cluster study.[318] Several commenters stress that any potential increase in transparency and interconnection process

[313] CESA Initial Comments at 8-9; Illinois Commission Initial Comments at 6; Puget Sound Initial Comments at 6; SPP Initial Comments at 4.

[314] CESA Initial Comments at 9; Illinois Commission Initial Comments at 6.

[315] Puget Sound Initial Comments at 6.

[316] SPP Initial Comments at 4.

[317] CESA Initial Comments at 8.

[318] CREA and NewSun Initial Comments at 48.

performance resulting from this proposal must outweigh the additional burden imposed on transmission providers.[319]

(c) Comments on Specific Proposal

(1) Metrics

111. While some commenters agree with the Commission's proposed table of metrics,[320] multiple commenters suggest additional metrics that should be posted.[321] For instance, Public Interest Organizations request information on the available interconnection capacity (including, at a minimum, a snapshot of existing available interconnection capacity and associated transmission during high load conditions for each substation) including projects already in the interconnection queue, and the capacity those projects are requesting,[322] as well as metrics on whether power flows from a point of interconnection are likely to serve low income and people of color communities (which would be consistent with Executive Order 13985).[323] Other commenters suggest that the

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[319] Cypress Creek Initial Comments at 14; EEI Initial Comments at 12-13; Eversource Initial Comments at 11; New Jersey Commission Initial Comments at 22-23; New York State Department Initial Comments at 8-9.

[320] NOPR, 179 FERC ¶ 61,194 at P 51.

[321] Ameren Initial Comments at 5; Bonneville Initial Comments at 7; Clean Energy Buyers Initial Comments at 7-8; MISO Initial Comments at 25 (agreeing that the five data points are sufficient but adding that, if the first is provided, then prospective interconnection customers can calculate the other four).

[322] Public Interest Organizations Initial Comments at 19-20.

[323] Public Interest Organizations Reply Comments at 11-12 (citing 16 U.S.C. 824(a); *Nat'l Ass'n for Advancement of Colored People v. FPC*, 425 U.S. 662, 669-670 (1976); Executive Order 13985, "Executive Order on Advancing Racial Equity and Support for

posted metrics should also include: circuit strength and the harmonics of transmission system elements;[324] limiting elements at a substation or associated transmission infrastructure;[325] the level of congestion and resource curtailment by location (historic, current, and/or expected);[326] overload conditions;[327] contingencies that drive the impacts to the monitored facility;[328] for a given transmission line, information on the circuit (e.g., single or double), the conductor type, pole types, the ratings of the equipment, and the age of the equipment;[329] flowgate data, such as disconnect switches, breakers, transformers, conductors, series reactors, and ground clearances of lines;[330] change file models of network upgrades for deliverability in advance of providing study results;[331]

Underserved Communities Through the Federal Government" (Jan. 20, 2021)); *see also* Navajo Utility Initial Comments at 9.

[324] SEIA Initial Comments at 6.

[325] AES Initial Comments at 5-7; Hannon Armstrong Initial Comments at 2; Pattern Energy Initial Comments at 23; Public Interest Organizations Initial Comments at 19.

[326] AEP Initial Comments at 13; Clean Energy Associations Initial Comments at 12; Pine Gate Initial Comments at 14.

[327] Ameren Initial Comments at 6; R Street Initial Comments at 10.

[328] Pattern Energy Initial Comments at 23.

[329] NextEra Initial Comments at 11.

[330] AES Initial Comments at 6; Pattern Energy Initial Comments at 23; Pine Gate Initial Comments at 14; SEIA Reply Comments at 4.

[331] AES Initial Comments at 5; Pine Gate Initial Comments at 14; SEIA Reply Comments at 5.

base case models paired with contingencies including local contingencies (below 200 kV);[332] incremental injection capacity available at each bus in the transmission provider's footprint under N-1 conditions with a five-year outlook;[333] the rating of the monitored facility;[334] estimated costs of interconnection or transmission service, including where interconnection is likely to be costly and not costly;[335] proposed upgrades in the region that could affect interconnection requests;[336] lists of potential upgrades that would be needed to export power to other regions or that would allow the transmission provider to increase injection capacity at each substation;[337] more granular load growth data, defined by region, which could be combined with existing and planned generation and congestion to view anticipated system changes;[338] and the share that all generating facilities contribute to a network upgrade along with their share of allocated costs.[339] Tesla requests information that would particularly developers of non-

[332] AES Initial Comments at 5; SEIA Reply Comments at 5.

[333] AES Initial Comments at 5; SEIA Reply Comments at 5.

[334] Pattern Energy Group Initial Comments at 23; SEIA Reply Comments at 5.

[335] Bonneville Initial Comments at 5; Eversource Initial Comments at 11.

[336] Ørsted Initial Comments at 7; Pattern Energy Initial Comments at 23; Public Interest Organizations Initial Comments at 19; SEIA Reply Comments at 5.

[337] Clean Energy Associations Initial Comments at 13; Public Interest Organizations Initial Comments at 20-21.

[338] Google Initial Comments at 6, 14.

[339] AES Initial Comments at 5-7, 13-14.

synchronous generating facilities to decide what project controls might be best suited for a given point of interconnection, including: the number of generating facilities and power control devices (including series compensation systems, static synchronous compensator devices and other power control devices) that are two busses away from the given point of interconnection; the circuit breaker short circuit ratings of the nearest substation; and the maximum and minimum fault current in megavolt amperes (MVA) at the given point of interconnection.[340]

112. Several commenters highlight that additional information regarding transmission system conditions, such as previous cluster studies and models, posted in a secure way subject to CEII processes, would allow interconnection customers to conduct their own initial analyses of system conditions and desirable points of interconnection.[341] SoCal Edison states that, alternatively, the transmission providers could identify areas where new generation is desired, guided by state processes identifying the locations that can accommodate additional generation currently or locations intended for types of generation sought state policy.[342]

[340] Tesla Initial Comments at 7.

[341] ACE-NY Initial Comments at 11; AES Initial Comments at 5; Clean Energy States Alliance Initial Comments at 4; CREA and NewSun Initial Comments at 47; ENGIE Initial Comments at 3; NextEra Reply Comments at 9; PJM Initial Comments at 7; PPL Initial Comments at 9; SEIA Reply Comments at 4.

[342] SoCal Edison Initial Comments at 14-15.

113. Some commenters oppose these requests for additional metrics. Dominion notes that tracking and providing the information requested by Public Interest Organizations, including documenting the study process, providing enhanced interconnection queue tracking, and metrics on constraints that cause bottlenecks, would be burdensome, taking engineers' time, slowing down the cluster study process, and diverting resources.[343] EEI and WIRES contend that certain information on transmission line design, such as circuit type, conductor type, and pole type, would be overly burdensome and offer little benefit, adding that this information could invite potential disputes or be used to threaten to the reliability of the transmission system or for commercial gain if the information is not subject to confidentiality protections.[344] EEI also asserts that any additional information beyond that proposed in the NOPR would complicate the interconnection process by adding another potential area of dispute and risks potential "backseat driving" by the interconnection customer, while the transmission provider is responsible for performing and standing by its study results.[345]

114. Some commenters disagree as to the appropriate level of granularity of the required metrics. SEIA and ENGIE support the NOPR proposal to require transmission providers to post bus-level interconnection capacity constraints.[346] Dominion disagrees,

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[343] Dominion Reply Comments at 8.

[344] EEI Reply Comments at 9-10; WIRES Reply Comments at 5-6.

[345] EEI Reply Comments at 9-10.

[346] ENGIE Initial Comments at 2-3; SEIA Initial Comments at 5.

arguing that requiring capacity constraint information to be provided at the bus-level is outside the scope of the NOPR and would not necessarily be useful in a networked system where injection at one bus will affect the capability at other buses and significant additional power flow analysis would be required to determine these values at each bus.[347] According to Dominion, information about bus-level interconnection capacity constraints makes more sense where the system is radial in nature and injection capability at one bus is not dependent on contingencies or injections at another bus. Eversource adds that bus level information will not provide significant benefits because it may be too simplistic if it is not based on N-1 conditions or if it fails to incorporate stability considerations.[348] Public Interest Organizations state that many utilities provide hosting capacity information on their websites at the distribution level in heatmaps or tables, in particular to help distributed solar interconnection customers, and this information is required by states and updated regularly.[349] Public Interest Organizations ask the Commission to require analogous hosting capacity information to be provided by transmission providers for all potential generation locations with exemptions for urban substations where there is limited potential for generation development. PJM requests

[347] Dominion Reply Comments at 8-9.

[348] Eversource Initial Comments at 11.

[349] Public Interest Organizations Initial Comments at 20 (citing National Renewable Energy Laboratory, Advanced Hosting Capacity Analysis, https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html).

that, rather than requiring that all buses be made available in a large RTO/ISO, a transmission provider should be allowed to screen and only present the majority of the feasible points of interconnection.[350] As an alternative to providing information at every bus, Tri-State states that a transmission provider could post the most recent cluster study to provide information for the buses that were studied as opposed to studying all buses on the system, while also making clear that the heatmap does not reflect interconnection requests in neighboring systems.[351] Similarly, Bonneville argues that cluster studies would not provide the incremental injection capacity at each bus on the transmission provider's system, which would warrant a separate study, and therefore, transmission providers should be afforded flexibility to provide this capacity information as it becomes available.[352]

115. Some commenters argue that the proposed heatmap is not an ideal way to present public interconnection information. For instance, Illinois Commission states that it is not immediately evident what information maps posted to an RTO/ISO website would reflect.[353] For example, Illinois Commission questions whether congestion maps would reflect present congestion or congestion that might arise after generating facilities interconnect. Fervo Energy states that additional research might be needed to determine

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[350] PJM Initial Comments at 48-49.

[351] Tri-State Initial Comments at 8.

[352] Bonneville Initial Comments at 6-7.

[353] Illinois Commission Initial Comments at 6.

the most useful informational suite.[354] Clean Energy Associations proposes, and SEIA supports, that two maps, one for Energy Resource Interconnection Service (ERIS) and one for capacity or NRIS, should be made available where appropriate, and notes that in ISO-NE overlapping impact analysis is used to determine eligibility for capacity NRIS.[355] Finally, Clean Energy Associations and ISO-NE recommend that the Commission consider allowing information to be qualitative, such that, rather than a "hosting map," transmission providers could post a map and accompanying report regarding system conditions at various points on the transmission system.[356]

(2) <u>Security of Critical Information</u>

116. Several commenters express concern that the NOPR's proposed heatmap and/or metrics may create a security risk[357] by, among other things, indicating areas where transmission is heavily loaded and more vulnerable to interference.[358] In particular, LADWP and Bonneville express concerns over sharing distribution factor and MW

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[354] Fervo Energy Reply Comments at 3.

[355] Clean Energy Associations Initial Comments at 12; SEIA Reply Comments at 5.

[356] Clean Energy Associations Reply Comments at 3; ISO-NE Initial Comments at 17.

[357] EEI Reply Comments at 9-10; Indicated PJM TOs Initial Comments at 15; LADWP Initial Comments at 3; NRECA Initial Comments at 16-17; PacifiCorp Initial Comments at 16; PPL Initial Comments at 8; SoCal Edison Initial Comments at 13-14; WIRES Reply Comments at 5-6.

[358] LADWP Initial Comments at 3; PacifiCorp Initial Comments at 16; PPL Initial Comments at 8.

impact, which they believe could identify highly stressed transmission lines, as well as concerns with identifying the line locations, which are not currently provided publicly.[359] LADWP further expresses concern with CEII issues that may arise from publicly releasing a table of metrics regarding the estimated impact of a potential generating facility.[360]

117. Other commenters counter that the security risks associated with the NOPR proposal are reasonable or non-existent. For example, Pacific Northwest Utilities and Puget Sound states that the purpose of the heatmap is to provide an overview of interconnection capacity, which is unlikely to implicate CEII, and thus the risk of unrestricted critical infrastructure information should be low.[361] Indicated PJM TOs and PPL state that a visual map with limited information, excluding reliability constraints or other particular information that could be used to identify vulnerabilities, could be made public without security concerns and highlight PJM as a good example of this.[362] Xcel states that it does not have security concerns about posting estimated injection capacity

[359] Bonneville Initial Comments at 6; LADWP Initial Comments at 3.

[360] LADWP Initial Comments at 3.

[361] Pacific Northwest Utilities Initial Comments at 15; Puget Sound Initial Comments at 6-7.

[362] Indicated PJM TOs Initial Comments at 14-15; PPL Initial Comments at 8-9.

but that some of the more detailed information should be limited.[363] MISO states that it is currently unaware of any security concerns associated with the proposal.[364]

118. While SoCal Edison and Southern assert that there should be no requirement on transmission providers to make public or display any CEII or confidential information,[365] other commenters contend that the CEII label should not be used to unreasonably impede interconnection customers' access to interconnection information necessary to understand the cost and other impacts of locating their projects in different areas of the transmission system.[366] Some commenters recommend that the Commission require transmission providers to make CEII data available only to interconnection customers who meet restricted access requirements, such as through a secure portal or subject to a confidentiality agreement.[367] Pattern Energy asks that this information be made available through a cost-free process that takes no longer than two weeks,[368] and Pine Gate adds that the retrieval of this information should not require background checks, as required by

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[363] Xcel Initial Comments at 22.

[364] MISO Initial Comments at 27.

[365] SoCal Edison Initial Comments at 14; Southern Initial Comments 28.

[366] CESA Reply Comments at 4; Google Reply Comments at 7; Pattern Energy Initial Comments at 24.

[367] Google Reply Comments at 7; Indicated PJM TOs Initial Comments at 15; ISO-NE Initial Comments at 17; NRECA Initial Comments at 16; Pattern Energy Initial Comments at 24; SEIA Initial Comments at 6; SEIA Reply Comments at 5.

[368] Pattern Energy Initial Comments at 24.

certain transmission providers.[369] EEI suggests that transmission providers should have the discretion to identify sensitive information that should be withheld.[370] Clean Energy States add that the Commission may want to limit access to permitted users, controlling the copying and dissemination of data, or take other security measures.[371]

(3) <u>Miscellaneous</u>

119. SEIA requests that the Commission require transmission providers to use the most recent available study models as well as the most recently completed system impact study in creating their data results.[372]

120. A few commenters express concern with the proposal to require updated information 30 days after the completion of each cluster study and restudy and instead request that the Commission allow for regional flexibility on the timing of updates.[373] MISO states that, as written, the NOPR proposal would require it to update the tool available to help interconnection customers pre-screen for potential points of interconnection each time a regional system impact study is issued, which would be numerous times during a calendar year due to the configuration of MISO's transmission

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[369] Pine Gate Initial Comments at 14.

[370] EEI Initial Comments at 13.

[371] Clean Energy States Initial Comments at 5.

[372] SEIA Initial Comments at 6.

[373] Bonneville Initial Comments at 8; El Paso Electric Initial Comments at 7; MISO Initial Comments at 26; Pacific Northwest Utilities Initial Comments at 14; PJM Initial Comments at 49; Tri-State Initial Comments at 7.

system.[374] PJM states that it is not feasible for an RTO/ISO as large as PJM to update an interactive public interconnection information tool within 30 days after completing a cluster restudy.[375] PJM states that, once the tool includes light load results, it will be uploading four to six datasets a year with each dataset including millions of points of interconnection flowgate records, which may eventually not be feasible to maintain from a storage perspective. According to El Paso Electric, the interconnection queue changes often as interconnection customers withdraw their requests and therefore transmission providers should not be required to update capacity line estimates monthly because the burden on staff could increase interconnection study delays.[376] Tri-State explains that only a subset of buses and lines are studied in each cluster study, so to require an estimate of the injection capacity at every bus in each cluster study to be posted within 30 days would greatly increase the scope and cost and would likely have a negative impact on the time to complete the study and cause rates to increase.[377]

121. On the other hand, Ørsted notes that any system representation needs to be frequently updated to be useful and avoid the risk of becoming out-of-date,[378] and Public Interest Organizations state that hosting capacity data should be updated at least

[374] MISO Initial Comments at 26-27.

[375] PJM Initial Comments at 49.

[376] El Paso Electric Initial Comments at 7.

[377] Tri-State Initial Comments at 7.

[378] Ørsted Initial Comments at 6.

quarterly.[379] Environmental Defense Fund argues that the public interconnection information should be updated immediately at the end of each cluster request window so that interconnection customers using that information are informed of generating facilities being studied that may impact transmission capacity.[380]

(4) Requests for Flexibility

122. Several commenters request flexibility from the Commission with respect to the particular information included in a potential heatmap.[381] Dominion asserts that the proposal is overly prescriptive and that the Commission should focus on the goal itself rather than uniformity.[382] Clean Energy Associations state that the heatmaps may need to be tailored to the services offered by a particular transmission provider, because their services are not uniform.[383] Several commenters claim that flexibility will help ensure that the information provided is useful and understandable, and will place a reasonable level of burden on transmission providers.[384] MISO states that flexibility is reasonable

[379] Public Interest Organizations Initial Comments at 20.

[380] Environmental Defense Fund Initial Comments at 3.

[381] Avangrid Initial Comments at 21-22; Bonneville Initial Comments at 6-8; Dominion Initial Comments at 14; MISO Initial Comments at 27; NY Commission and NYSERDA Initial Comments at 8; NYTOs Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 14; PJM Initial Comments at 48; Puget Sound Initial Comments at 6; SEIA Initial Comments at 6; Southern Initial Comments at 28; SPP Initial Comments at 4; WAPA Initial Comments at 7-8.

[382] Dominion Initial Comments at 13.

[383] Clean Energy Associations Initial Comments at 12.

[384] Avangrid Initial Comments at 21-22; Bonneville Initial Comments at 6-8;

given the burden on transmission providers of maintaining a heatmap tool relative to the limited value of frequent updates given that few interconnection customers use this tool and its inability to include future queued projects that will be relevant to the prospective interconnection customer.[385] Bonneville also argues that flexibility is needed to ensure consistency with security requirements.[386] On the other hand, Cypress Creek asserts that, as a broad consideration, the particular types of information to be made transparent that are valuable should be determined by the Commission in consultation with market participants who are best positioned to identify information relevant to financing and constructing new projects.[387]

123. Several commenters ask for flexibility in the way information is shared. SEIA states that whether the data are in a map or other format is not as important as the product itself.[388] NYTOs expect that flexibility would allow regions to adopt some form of the virtual tool as long as it is clear that the information is illustrative, non-binding, and subject to change.[389] NRECA states that smaller generation and transmission

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Cypress Creek Initial Comments at 14; MISO Initial Comments at 27; NY Commission and NYSERDA Initial Comments at 7-8; NYTOs Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 14; WAPA Initial Comments at 8.

[385] MISO Initial Comments at 26-27.

[386] Bonneville Initial Comments at 6.

[387] Cypress Creek Initial Comments at 14.

[388] SEIA Initial Comments at 6.

[389] NYTOs Initial Comments at 9.

cooperatives may be able to just post a table with bus names and injection capability and present the same useful information in a more economical way.[390] NV Energy states that, if it were to post to its OASIS the CAISO locational marginal price map with a link to CAISO's OASIS to provide a list of interchange limits and interchange schedules, this would be just as valuable as a map for its own transmission system.[391]

124. Some commenters argue that transmission providers that already provide public interconnection information should have flexibility to use their existing systems to comply.[392] However, Environmental Defense Fund avers that this flexibility should not extend to transmission providers who, prior to the NOPR, were without a substantial public interconnection information system, because they have no sunk costs related to public interconnection information systems.[393]

125. Several commenters express concern that heatmaps would be technically difficult to implement outside of RTOs/ISOs and ask the Commission to provide non-RTO/ISO regions with flexibility in how they comply with the mapping tool.[394] Tri-State states

[390] NRECA Initial Comments at 16.

[391] NV Energy Initial Comments at 10.

[392] Environmental Defense Fund Reply Comments at 4; OMS Initial Comments at 6.

[393] Environmental Defense Fund Reply Comments at 4.

[394] Dominion Initial Comments at 12-14; NRECA Initial Comments at 16; NV Energy Initial Comments at 10; PPL Initial Comments at 9; Puget Sound Initial Comments at 5-6; Tri-State Initial Comments at 8.

that, in non-RTO/ISO regions, it is common for multiple transmission providers to use a single substation, making injection capacity dependent on interconnection requests in neighboring interconnection queues and their associated study assumptions.[395] Tri-State, therefore, encourages the Commission to permit variations among heatmaps, adding that entities in non-RTOs/ISOs should not be required to study every bus.[396]

126. Xcel recommends that the Commission consider applying the requirement only in RTO/ISO regions or granting non-RTO/ISO transmission providers sufficient time, such as two years, to comply.[397] WAPA asks the Commission to first require data visualization by larger utilities, wait approximately 18 months after implementation, and then measure the benefits of interactive tools produced by larger utilities, giving stakeholders a chance to comment before extending the heatmap requirement.[398]

127. On the other hand, some commenters expressly argue that uniformity should be required inside and outside of RTO/ISO regions.[399] Google states that such publicly available information would begin to address the critical information advantage that transmission owners have over independent power producers, particularly in non-

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[395] Tri-State Initial Comments at 8.

[396] *Id.*; *see also* Eversource Initial Comments at 11.

[397] Xcel Initial Comments at 22.

[398] WAPA Initial Comments at 8.

[399] Environmental Defense Fund Reply Comments at 3; Fervo Energy Reply Comments at 3; Google Initial Comments at 6; R Street Initial Comments at 10.

RTO/ISO regions.[400] R Street notes that non-RTO/ISO regions may have additional challenges in implementing such a tool but states that this should not eliminate their requirement to do so and those regions could be granted extra implementation time.[401]

(d) Requests for Clarification or Technical Conference

128. Several commenters seek clarification on the information transmission providers are required to present in the heatmap, use of that information, who has the responsibility of presenting the information, timing of updating that information and recovery of costs for providing this information. PJM asks that the Commission clarify that an interactive visual congestion map could comply, instead of requiring its specific form.[402]

129. APPA-LPPC ask the Commission to clarify that it is not proposing that transmission providers be required to conduct any individualized analyses or take any action in response to particular prospective interconnection customers' use of the interactive tools.[403]

130. Some commenters request that the Commission make clear that the public information is published only as a guide and not as a binding or definitive statement of

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[400] Google Reply Comments at 6.

[401] R Street Initial Comments at 10.

[402] PJM Initial Comments at 48.

[403] APPA-LPPC Initial Comments at 13-14.

available interconnection capacity or costs.[404] Xcel asks the Commission to clarify that transmission providers have no liability associated with the posting of public information.[405] EEI urges the Commission to make clear that interconnection customers that rely exclusively on this information, including these maps, do so at their own risk.[406]

131. Eversource asks that the Commission clarify that "no information would be required to be made available before the conclusion of the first cluster study."[407]

132. Dominion seeks clarification that, in an RTO/ISO context, the proposed requirements to maintain a visual representation would apply to the RTO/ISO, and not additionally to individual transmission owners.[408]

133. Several commenters request clarification on how the public information proposal will be funded.[409] Some commenters assert that a user-pays model is the only appropriate funding mechanism because not all interconnection customers will use the public information tools, and the transmission provider or their customers should not be required

[404] AECI Initial Comments at 5; AEE Initial Comments at 9; AEP Initial Comments at 13; Ameren Initial Comment at 6; CAISO Initial Comments at 8; Duke Southeast Utilities Initial Comments at 6-7; EEI Initial Comments at 12-13; National Grid Initial Comments at 8-9; New York State Department Initial Comments at 8; NYISO Initial Comments at 17; NYTOs Initial Comments at 9.

[405] Xcel Initial Comments at 22.

[406] EEI Initial Comments at 13.

[407] Eversource Initial Comments at 11.

[408] Dominion Initial Comments at 14.

[409] National Grid Initial Comments at 8; PacifiCorp Initial Comments at 14; Tri-State Initial Comments at 7-8.

to pay for work that only benefits some.[410] Tri-State asserts that it might increase the $5,000 application fee to cover the significant heatmap costs.[411]

134. AEP, Tesla, and ACORE ask the Commission to initiate a proceeding and hold a technical conference to, among other things, identify useful information tools that could be feasibly developed, establish uniform and transparent study assumptions, share best practices, and help less sophisticated interconnection customers learn to use available tools and information to lessen their own risk before entering an interconnection queue.[412]

iii. Commission Determination

135. We adopt, without modification, the NOPR proposal to revise *pro forma* LGIP section 6.4, now section 6.1, to require transmission providers to publicly post available information pertaining to generator interconnection (i.e., public interconnection information or a heatmap). We require transmission providers to update the heatmap within 30 calendar days after the completion of each cluster study and cluster restudy. Such heatmaps must be calculated under N-1 conditions and studied based on the power flow model of the transmission system with the transfer simulated from each point of interconnection to the whole transmission provider's footprint (to approximate NRIS), and with the incremental capacity at each point of interconnection decremented by the

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[410] National Grid Initial Comments at 8; PacifiCorp Initial Comments at 14.

[411] Tri-State Initial Comments at 8.

[412] ACORE Reply Comments at 3, AEP Initial Comments at 13, 15; Tesla Initial Comments at 6.

existing and queued generation at that location (based on the existing or requested interconnection service limit of such generation). We require transmission providers to provide the following information as outputs at each point of interconnection: (1) the distribution factor; (2) the MW impact (based on the proposed project size and the distribution factor); (3) the percentage impact on each impacted transmission facility (based on the MW values of the proposed project and the facility rating); (4) the percentage of power flow on each impacted transmission facility before the proposed project; and (5) the percentage power flow on each impacted transmission facility after the injection of the proposed project.

136. We find that the benefit of providing further transparency to interconnection customers about potential points of interconnection outweighs the added administrative burden to transmission providers. Commenters generally support supplementing the existing publicly available interconnection information and note their broad support for the NOPR proposal.[413] Many commenters further assert that the heatmap will provide

[413] ACE-NY Initial Comments at 11; AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; APPA-LPPC Initial Comments at 13; CAISO Initial Comments at 7; CESA Initial Comments at 7; Clean Energy Associations Initial Comments at 12; Clean Energy Buyers Initial Comments at 6-7; Colorado Commission Initial Comments at 8; Consumers Energy Initial Comments at 3; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; Environmental Defense Fund Reply Comments at 2-3; ELCON Initial Comments at 4; ENGIE Initial Comments at 2; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2; Google Initial Comments at 14; Google Reply Comments at 6; Illinois Commission Initial Comments at 6; Interwest Initial Comments at 7; New Jersey Commission Initial Comments at 11-12; Northwest and Intermountain Initial Comments at 9-10; NY Commission and NYSERDA Initial Comments at 8; Ørsted Initial Comments at 7; Pattern Energy Initial Comments at 23; Pine Gate Initial Comments at 13; Public Interest

valuable information to interconnection customers before they enter the interconnection queue,[414] and as SEIA explains, interconnection customers currently lack substantial information prior to entering the interconnection queue, which is valuable in determining whether to proceed with a proposed generating facility.[415] In particular, the information that we require transmission providers to provide to prospective interconnection customers will allow such interconnection customers to learn about available interconnection capacity as well as other metrics that reflect the impact of the addition of a proposed generating facility to the transmission provider's transmission system at a particular point of interconnection. Such information may allow a prospective interconnection customer to estimate expected congestion,[416] and, in turn, to assess likely

Organizations Initial Comments at 18-19; R Street Initial Comments at 8, 10; R Street Reply Comments at 2; Southern Initial Comments at 28; Tesla Initial Comments at 6-7; Vistra Initial Comments at 1, 4.

[414] Alliant Energy Initial Comments at 5; Clean Energy Associations Initial Comments at 12; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; EEI Initial Comments at 12-13; ELCON Initial Comments at 6; ENGIE Initial Comments at 2; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2-3; Google Initial Comments at 4; Illinois Commission Initial Comments at 6; Indicated PJM TOs Initial Comments at 14; Indicated PJM TOs Reply Comments 6; ISO-NE Initial Comments at 26-27; New Jersey Commission Initial Comments at 12; NY Commission and NYSERDA Initial Comments at 8; Ohio Commission Consumer Advocate Initial Comments at 7; Pacific Northwest Utilities Initial Comments at 13; SEIA Initial Comments at 5.

[415] SEIA Initial Comments at 6.

[416] Google Initial Comments at 14.

network upgrades triggered by a proposed generating facility or the possibility of curtailment of a proposed generating facility.

137. With access to this type of information, a prospective interconnection customer will be able to better assess the viability of a proposed generating facility before it submits an interconnection request and therefore may be able to submit fewer exploratory and unviable interconnection requests. We believe that, by reducing the number of speculative interconnection requests, this reform will reduce the delays caused by restudies triggered by interconnection request withdrawals and overcrowded interconnection queues.[417] We believe that this information is also beneficial in the cluster study context, contrary to some commenters' concerns regarding the availability of information about the composition of the cluster and the effect of the other proposed generating facilities in the cluster. In fact, interconnection customers will be able to evaluate the viability of their proposed generating facility in the context of a cluster by using the publicly posted information as a baseline and incorporating the cluster information that transmission providers are required to post, during the customer engagement window, per new *pro forma* LGIP section 3.4.5 (Customer Engagement

[417] *See* CESA Initial Comments at 9; CESA Reply Comments at 3; Consumers Energy Initial Comments at 3; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; EEI Initial Comments at 12-13; ELCON Initial Comments at 6; Evergreen Action Initial Comments at 3; Google Initial Comments at 14; Illinois Commission Initial Comments at 6-7; New Jersey Commission Initial Comments at 12; NY Commission and NYSERDA Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 13; SEIA Initial Comments at 5.

Window). Further, the heatmap requirement will standardize the information available to interconnection customers across regions and such standardization will provide interconnection customers with consistency as they assess the viability of proposed generating facilities, including where to site them, across regions.[418] Despite MISO's assertion that interconnection customers typically use their own tools to conduct analyses, as opposed to MISO's heatmap, several commenters identify MISO's heatmap tool as an example of a transmission provider posting generator interconnection information that is useful for prospective interconnection customers.[419] Therefore, we continue to find that it is important to make similar information available to prospective interconnection customers across the country to ensure comparable access to information and the above mentioned resultant benefits of such information for the interconnection process.

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[418] *See, e.g.*, Alliant Energy Initial Comments at 5; Clean Energy Associations Initial Comments at 12.

[419] ACE-NY Initial Comments at 11; AES Initial Comments at 3; Affected Interconnection Customers Initial Comments at 30; APPA-LPPC Initial Comments at 13; CAISO Initial Comments at 7; CESA Initial Comments at 7; Clean Energy Associations Initial Comments at 12; Clean Energy Buyers Initial Comments at 6-7; Colorado Commission Initial Comments at 8; Consumers Energy Initial Comments at 3; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; ELCON Initial Comments at 4; ENGIE Initial Comments at 2; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2; Google Initial Comments at 14; Google Reply Comments at 6; Illinois Commission Initial Comments at 6; Interwest Initial Comments at 7; New Jersey Commission Initial Comments at 11-12; Northwest and Intermountain Initial Comments at 9-10; NY Commission and NYSERDA Initial Comments at 8; Ørsted Initial Comments at 7; Pattern Energy Initial Comments at 23; Pine Gate Initial Comments at 13; Public Interest Organizations Initial Comments at 18-19; R Street Initial Comments at 8, 10; Southern Initial Comments at 28; Tesla Initial Comments at 6-7; Vistra Initial Comments at 1, 4.

138. Some commenters assert that the NOPR proposal is not useful[420] in part because it does not provide sufficient detail and may not correspond with future study conditions,[421] its usefulness depends on its implementation,[422] and it is unlikely to address cost uncertainty challenges.[423] In response to such objections, we find that the public interconnection information requirements we adopt in this final rule will provide further transparency of interconnection conditions, but, as we have acknowledged above, will remain non-binding and therefore cannot provide cost certainty. We recognize that this requirement does not provide real-time transmission system information, but we find that this information is valuable to prospective interconnection customers before they enter the interconnection queue.

139. We disagree with commenters that assert that the NOPR proposal is overly burdensome.[424] By moving the *pro forma* LGIP from a serial to a cluster study process,

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[420] Dominion Initial Comments at 13; Idaho Power Initial Comments at 3; ISO-NE Initial Comments at 17; NextEra Initial Comments at 12; New York State Department Initial Comments at 8; NYISO Initial Comments at 17; Omaha Public Power Initial Comments at 4; PacifiCorp Initial Comments at 14.

[421] Dominion Initial Comments at 13; New York State Department Initial Comments at 8; Omaha Public Power Initial Comments at 4.

[422] Indicated PJM TOs Initial Comments at 14; New York State Department Initial Comments at 8; NYTOs Initial Comments at 9; SPP Initial Comments at 4.

[423] AEE Initial Comments at 9; Cypress Creek Initial Comments at 13.

[424] Dominion Initial Comments at 13; National Grid Initial Comments at 8; New York State Department Initial Comments at 8; NextEra Initial Comments at 12; Omaha Public Power Initial Comments at 4; Pacific Northwest Utilities Initial Comments at 14; PPL Initial Comments at 9; Tri-State Initial Comments at 4; WAPA Initial Comments at

the reforms adopted in this final rule will reduce the number of studies and restudies performed by transmission providers, therefore reducing the burden on both transmission providers and their staff. In addition, as commenters assert, and we agree, the information posting and interactive capability we require in this final rule could feasibly be implemented with available industry system simulation tools.[425] We also agree with Clean Energy Associations that providing these data in a standardized format should be a "relatively low-impact" requirement for transmission providers.[426] This appears to be consistent with comments from Dominion that suggests that the majority of the burden associated with complying with this reform will be through an up-front financial commitment in new software, rather than ongoing costs.[427] Having made such software commitments, though, transmission providers should be able to automate much of the heatmap development, without significant commitments of staff or resources. In doing so, we expect the ongoing costs of maintaining such a heatmap to be relatively low. Moreover, because transmission providers must use the most recent cluster study or

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[425] APPA-LPPC Initial Comments at 13; Pennsylvania Commission Initial Comments at 13, which explains that transmission providers are already implementing these tools further illustrates the point: heatmaps will not likely cause further delay in already-stressed queues.

[426] Clean Energy Associations Initial Comments at 23-13; *see also* ACORE Reply Comments at 3 (stating that collaboration to increase automation of interconnection studies is a best practice that could be adopted elsewhere).

[427] Dominion Initial Comments at 12.

cluster restudy to populate the heatmap, they will not face the burden of individualized analyses, which addresses the concern raised by some commenters.[428]

140. We adopt the requirement for transmission providers to update the heatmaps within 30 calendar days after the completion of each cluster study and cluster restudy. We recognize the need to balance the burden of a specific update frequency with the value of ensuring uniform, up-to-date information that can inform prospective interconnection customers evaluating whether to enter the next cluster. While some commenters support the timeline proposed in the NOPR,[429] others argue that it is overly burdensome or, given the division of their footprint into regions that have different timelines, would trigger frequent updates. We find that the requirements we adopt here establish an appropriate period of time because, as discussed above, once the necessary software is in place, updating the heatmap after the completion of a study is expected to be largely automated without significant commitments of staff or resources. As the record demonstrates, such heatmaps can be implemented with available industry system simulation tools[430] and with a standardized format that causes the burden to be a

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[428] *See* APPA-LPPC Initial Comments at 13-14.

[429] Environmental Defense Fund Initial Comments at 3; Ørsted Initial Comments at 6; Public Interest Organizations Initial Comments at 20.

[430] APPA-LPPC Initial Comments at 13-14; Pennsylvania Commission Initial Comments at 13.

"relatively low-impact" requirement for transmission providers,[431] once transmission providers have invested in new software.[432]

141. In response to Eversource, which asks the Commission to clarify that the heatmap would not be required to be made available before the first cluster study concludes,[433] we agree and further clarify that the heatmap would not be required to be made available until after the transition period. In response to El Paso Electric's comments regarding the burden of a monthly update,[434] we clarify that the heatmaps must be updated within 30 calendar days after the completion of each cluster study and cluster restudy, not on a cycle of every 30 calendar days.

142. In response to comments from PJM, Bonneville, and Tri-State requesting flexibility for the posting of information for points of interconnection that have yet to be studied,[435] we clarify that transmission providers need to provide updates only for anything that has changed in the most recent cluster study or restudy after the first cluster study after the Commission-approved effective date of the transmission provider's filing

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[431] Clean Energy Associations Initial Comments at 23-13; *see also* ACORE Reply Comments at 3 (stating that collaboration to increase automation of interconnection studies is a best practice that could be adopted elsewhere).

[432] Dominion Initial Comments at 12.

[433] Eversource Initial Comments at 11.

[434] El Paso Electric Initial Comments at 7.

[435] Bonneville Initial Comments at 6; PJM Initial Comments at 48-49; Tri-State Initial Comments at 8.

in compliance with this final rule. Requiring transmission providers to study each potential point of interconnection, rather than just those requested in each cluster, would expand the scope of this requirement. In turn, requiring such expanded studies would be inconsistent with ensuring that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner. In response to PJM, which states that transmission providers should be allowed to use prescreened datasets that capture a majority of the feasible points of interconnection that remove existing generator buses on the low side of the generator step-up unit, rather than using all buses to populate the heatmap,[436] we agree that the heatmap may not differ significantly between the existing generating facility's point of interconnection on the low voltage side of the generating facility's step-up unit and the high voltage side of the step-up unit. If that is the case, this final rule provides transmission providers with the flexibility to populate the heatmap with only the high side of the step-up unit.

143. In response to comments arguing that the Commission has failed to demonstrate that information already made available is inadequate,[437] we disagree. The heatmap requirement is distinct from information that transmission providers are already required

[436] PJM Initial Comments at 48-49.

[437] APPA-LPPC Initial Comments at 9; Duke Southeast Utilities Initial Comments at 6-7; Idaho Power Initial Comments at 3; New York State Department Initial Comments at 8; NV Energy Initial Comments at 10; NYISO Initial Comments at 17; Ohio Commission Consumer Advocate Initial Comments at 6-7; PacifiCorp Initial Comments at 14-15; PG&E Initial Comments at 9-10; SoCal Edison Initial Comments at 14.

to provide. The existing *pro forma* LGIP requires transmission providers to post the interconnection models and assumptions on OASIS or a password-protected website. But the information that we require to be posted in compliance with this final rule is the output of such models and assumptions. We believe that publicly posting such resulting output is necessary to aid prospective interconnection customers in their decision-making prior to entering the interconnection queue. While interconnection customers, on their own or through the hiring of consultants, may be capable of performing studies with information already published by transmission providers to arrive at information similar to that required as part of this final rule, we believe that making high-level information more easily accessible to all prospective interconnection customers is needed to remedy unjust and unreasonable Commission-jurisdictional rates. While Order No. 845 and FERC Form 715 do require certain, more detailed information to be filed with the Commission and/or posted on OASIS or a password-protected website,[438] access to this information has not addressed the problem of speculative interconnection requests that we aim to remedy with several reforms adopted in this final rule.

144. We recognize the need to balance security concerns with the benefits of additional transparency. While some commenters express security-related concerns with the NOPR proposal,[439] as discussed below, we are not modifying the Commission's CEII

[438] Order No. 845, 163 FERC ¶ 61,043 at P 236.

[439] Bonneville Initial Comments at 6; Indicated PJM TOs Initial Comments at 15; LADWP Initial Comments at 3; NRECA Initial Comments at 16-17; PacifiCorp Initial Comments at 16; PPL Initial Comments at 8; SoCal Edison Initial Comments at 13-14.

procedures,[440] which we believe are sufficient to address security concerns raised in comments. Some commenters state that publicly posting information that indicates areas of transmission congestion or constraints is a risk as these areas are more vulnerable. We are not persuaded by these concerns and note that location-specific congestion information is already publicly available in RTO/ISO markets. Moreover, the Commission's regulations already provide that, upon request, transmission providers must make available all data used to calculate available transfer capability, total transfer capability, capacity benefit margin, and transmission reliability margin for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability)).[441] Additionally, we find these concerns to be speculative, particularly in light of the fact that MISO already provides similar information over a large area. Rather, we agree with those commenters that do not believe that the NOPR proposal introduces additional security concerns.[442]

145. In response to concerns from PPL and LADWP regarding the distribution factor analysis being made public,[443] we are not persuaded and find these concerns to be speculative as well. MISO has long made distribution factors publicly available and

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[440] 18 CFR 388.113 (2022), which govern "the procedures for submitting, designating, handling, sharing, and disseminating [CEII] *submitted to or generated by the Commission*" (emphasis added).

[441] 18 CFR 37.6(b)(2) (2022).

[442] MISO Initial Comments at 27.

[443] LADWP Initial Comments at 3; PPL Initial Comments at 8-9.

states it is currently unaware of any security concerns associated with the proposal.[444] As such, there is no evidence in the record to suggest this posting has raised any concerns in the past. Moreover, we observe that the distribution factor analyses informing the heatmaps are the result of multi-year forward projections that inevitably diverge from actual, real-time conditions, mitigating any potential concerns with publicly posting this information.

146. We are similarly unpersuaded by potential data confidentiality concerns.[445] As with distribution factors, we find such concerns to be speculative and contrary to the experience of MISO, which, for the last several years, has already provided this information publicly,[446] as well as contrary to the statements of commenters that support the NOPR proposal and do not raise data confidentiality concerns.[447]

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[444] MISO Initial Comments at 27.

[445] Bonneville Initial Comments at 6; PPL Initial Comments at 9.

[446] Rod Walton, *MISO Introduces New Generation Interconnection Online Tool*, Power and Engineering (May 19, 2020), at https://www.power-eng.com/om/miso-introduces-new-generation-interconnection-online-tool/#gref.

[447] Affected Interconnection Customers Initial Comments at 30; AES Initial Comments at 3; ACE-NY Initial Comments at 11; APPA-LPPC Initial Comments at 13; CAISO Initial Comments at 7; CESA Initial Comments at 7; Clean Energy Associations Initial Comments at 12; Clean Energy Buyers Initial Comments at 7-8; Colorado Commission Initial Comments at 8; Consumers Energy Initial Comments at 3; CREA and NewSun Initial Comments at 44-45; Duke Southeast Utilities Initial Comments at 6; Environmental Defense Fund Initial Comments at 3; ELCON Initial Comments at 4; ENGIE Initial Comments at 2; Evergreen Action Initial Comments at 3; Fervo Energy Initial Comments at 2; Google Initial Comments at 14; Google Reply Comments at 6; Interwest Initial Comments at 7; Illinois Commission Initial Comments at 6; New Jersey Commission Initial Comments at 11- 12; NY Commission and NYSERDA Initial Comments at 8; Northwest and Intermountain Initial Comments at 9-10; Ørsted Initial

147. We provide further clarification in response to comments regarding the scope of analysis and assumptions which must provide the basis for the heatmaps. In response to comments from Public Interest Organizations,[448] we decline to specifically require the heatmap to be studied at high load conditions. Instead, we reiterate that such heatmap should be based on the power flow model of the cluster study or restudy. While such cluster studies are often simulated at high load conditions, we understand that transmission providers typically conduct interconnection studies by studying a variety of situations. As such, we clarify that the information posted, for consistency and actionability, must not only be based on the cluster studies, but also must reflect the most limiting result of each of these situations studied.

148. We find that it is necessary for the heatmaps to reflect N-1 conditions because transmission systems are operated to withstand N-1 contingencies. To the extent that such information was not calculated under N-1 conditions, the results would not be useful or sufficiently actionable to potential interconnection customers. As Eversource asserts, point of interconnection level information would be too simplistic if it is based only on N-0 conditions and would not provide prospective interconnection customers with the information necessary to select viable points of interconnection.[449] Similarly, we find

Comments at 7; Pine Gate Initial Comments at 13; Public Interest Organizations Initial Comments at 18-19; R Street Initial Comments at 8, 10; Southern Initial Comments at 28; Tesla Initial Comments at 6-7; Vistra Initial Comments at 1,4.

[448] Public Interest Organizations Initial Comments at 20.

[449] Eversource Initial Comments at 11.

that it is necessary for such posted information to approximate NRIS because such level of interconnection service is generally subject to more stringent requirements and therefore, reflecting this type of service will cover both types of interconnection requests, whether they are NRIS or ERIS.[450] Similar to information calculated under only N-0 conditions, to the extent such a heatmap was not calculated to approximate NRIS, the results would not be useful or sufficiently actionable to a significant portion of interconnection customers.

149. In response to comments from AES,[451] we decline to require the heatmaps to include a five-year outlook of available interconnection capacity. The purpose of the heatmaps is to provide potential interconnection customers an idea of the amount of interconnection capacity available at the conclusion of each cluster study or restudy. Because we are requiring transmission providers to consider pending generating facilities when collating the information to make public, interconnection customers will be aware

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[450] Specifically, the *pro forma* LGIP defines NRIS service as "an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market-based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service." *Pro forma* LGIP section 1. Whereas, the *pro forma* LGIP defines ERIS as "an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System *on an as available basis*. Energy Resource Interconnection Service in and of itself does not convey transmission service." *Id.* (emphasis added).

[451] AES Initial Comments at 5-7.

of some of the future conditions on the transmission system. Further, any requirement to produce forecasts would place an additional burden on transmission providers that we find would outweigh its usefulness to interconnection customers.

150. In response to comments from Alliant Energy and Clean Energy Associations arguing that the assumptions used to produce the heatmap should be made clear to users,[452] we find that the assumptions used to produce the heatmap should be consistent with those used in the interconnection cluster studies. As those assumptions are already required to be publicly posted, along with the models themselves,[453] the assumptions used to produce the heatmap will be publicly posted via these preexisting requirements.

151. Tri-State describes difficulties associated with multiple transmission providers that inhabit a single substation. In such situations, we clarify that transmission providers must populate the required heatmaps using the results from their interconnection studies. In response to the Illinois Commission, we clarify that the heatmaps must represent potential congestion that might result after a generating facility interconnects, not present congestion values. The heatmap must reflect the base case assumptions from the most recent cluster study or cluster restudy. Such studies are not intended to analyze current operational conditions.

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[452] Alliant Energy Initial Comments at 5; Clean Energy Associations Initial Comments at 12-13.

[453] Order No. 845, 163 FERC ¶ 61,043 at P 236; *pro Forma* LGIP section 2.3.

152. We next respond to specific objections raised regarding the heatmaps' required level of granularity and scope, requested flexibilities regarding alternatives to the adopted reform, and clarifications regarding which transmission providers are required to provide heatmaps, whether heatmaps are non-binding, and how costs related to the heatmaps requirement are to be recovered. We decline to alter the level of granularity of the heatmaps from that proposed in the NOPR. As Ameren and MISO attest,[454] the five data points proposed in the NOPR are reasonable and sufficient to provide a high-level comparison between several points of interconnection, and therefore to satisfy the goals of this reform.

153. Similarly, consistent with support from ENGIE and SEIA,[455] we adopt the scope of the heatmap requirement proposed in the NOPR, which is the amount of point of interconnection-level interconnection capacity available to be injected at each point of interconnection. We decline to expand the scope of the reporting. We believe that the scope of information that we require transmission providers to publicly post appropriately balances the burdens on transmission providers associated with providing this information with the benefits that might be realized by prospective interconnection customers of having ready access to this information. In response to Dominion, which argues that point of interconnection-level information may not necessarily be useful

[454] Ameren Initial Comments at 5; Bonneville Initial Comments at 7; Clean Energy Buyers Initial Comments at 7-8; MISO Initial Comments at 25.

[455] ENGIE Initial Comments at 2-3; SEIA Initial Comments at 5.

because, in a networked system, injection at one point of interconnection will affect the capability at other points of interconnection,[456] we agree that injections at one location affect capabilities at other locations. Because the information provided by the transmission provider accounts for full transmission system conditions, interconnection customers should have the information they need to approximate the impact of their potential generating facility on the transmission system. For example, interconnection customers will know if they are proposing to interconnect near constrained regions even if those constraints are not necessarily at the proposed point of interconnection.

154. We decline to require transmission providers to provide additional interconnection information metrics, as requested by some commenters.[457] While we are supportive of increased transparency, we are not persuaded that the benefits of such information would outweigh the burden of tabulating and posting such information.

155. In response to ISO-NE, we decline to require that the heatmap be qualitative only.[458] We find that providing information only qualitatively would not provide interconnection customers information they could use to adequately mitigate risks such as

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[456] Dominion Reply Comments at 8-9.

[457] AEP Initial Comments at 13; AES Initial Comments at 5-7; Bonneville Initial Comments at 5; Clean Energy Associations Initial Comments at 12-13; CREA and NewSun Initial Comments at 43-44; ENGIE Initial Comments at 3; Eversource Initial Comments at 11; Google Initial Comments at 6, 14; Hannon Armstrong Initial Comments at 2; Pattern Energy Initial Comments at 23; Pine Gate Initial Comments at 14; Public Interest Organizations Reply Comments at 11-12; SEIA Initial Comments at 6; SoCal Edison Initial Comments at 14-15; Tesla Initial Comments at 7.

[458] Eversource Initial Comments at 11.

obtaining site control and providing significant deposits to the transmission provider in order to enter the interconnection queue. Thus, providing only qualitative information would be insufficient to address the lack of information available to interconnection customers prior to entering the interconnection queue, which leads to speculative interconnection requests and the problems identified in the need for reform section above.

156. In response to requests for flexibility for transmission providers to identify and post alternative heatmaps,[459] we decline to grant such additional flexibility. In this final rule, we establish a set of required information that transmission providers must publicly provide. We believe that this level of information is what is needed to address the lack of information available to interconnection customers prior to entering the interconnection queue, and therefore remedy the unjust and unreasonable Commission-jurisdictional rates discussed in Section II of this final rule. We therefore disagree that the proposal is overly prescriptive,[460] as we believe that the required information is necessary to adequately inform prospective interconnection customers. While we establish a set of required information, in response to comments from Clean Energy Associations that the heatmap

[459] Avangrid Initial Comments at 21-22; Bonneville Initial Comments at 6-8; Clean Energy Associations Initial Comments at 12; Dominion Initial Comments at 14; MISO Initial Comments at 27; NY Commission and NYSERDA Initial Comments at 8; NYTOs Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 14; PJM Initial Comments at 48; Puget Sound Initial Comments at 6; SEIA Initial Comments at 6; Southern Initial Comments at 28; WAPA Initial Comments at 7-8.

[460] Dominion Initial Comments at 13.

may need to be tailored to the services offered by a particular transmission provider,[461] and comments from Bonneville that flexibility would allow transmission providers to determine whether a different methodology would more clearly identify interconnection capability for interconnection customers,[462] we note that if transmission providers find value in providing additional or different information, they may propose such variations on compliance.

157. While we acknowledge that, as a result of the relative interconnection queue sizes and load levels, many transmission providers may have heatmaps that indicate negative interconnection capacity and thereby would simply be "red,"[463] we agree with R Street that providing a visual representation of available interconnection capacity is a best practice and should be required nationwide.[464] Moreover, we find that there is value in providing an all "red" heatmap, as such information will demonstrate to prospective interconnection customers the potential and likely network upgrade-related consequences associated with interconnecting. In other words, an all "red" heatmap sends a valuable signal to interconnection customers regarding where proposed generating facilities may be more or less economic to interconnect prior to entering the interconnection queue.

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[461] Clean Energy Associations Initial Comments at 12.

[462] Bonneville Initial Comments at 7-8.

[463] *See* PacifiCorp Initial Comments at 15.

[464] *See* R Street Initial Comments at 10.

158. Not only is there value in requiring this information from all transmission providers, we are not persuaded that the burden is so great as to outweigh the benefits for non-RTO/ISO transmission providers and for smaller transmission providers.[465] We acknowledge that RTOs/ISOs are operationally different from their non-RTO/ISO counterparts and that RTOs/ISOs are often more technologically advanced, but the requirement is to reproduce interconnection studies and publish the results in a heatmap. No commenter attests that existing interconnection studies in non-RTO/ISO regions fail to evaluate point of interconnection-level interconnection injection capability. Moreover, we find that by publicly reproducing the results of existing interconnection studies, the heatmaps will address the need for additional interconnection information that exists in both RTOs/ISOs and non-RTOs/ISOs. In other words, we find that there are unjust and unreasonable Commission-jurisdictional rates stemming from the lack of this information for prospective interconnection customers both within and outside of RTOs/ISOs and that this problem must be remedied. Additionally, as Environmental Defense Fund comments, at least one other relatively small transmission owner posts an interactive capacity heatmap for its distribution system comparable to that required by this final

[465] Dominion Initial Comments at 12; NRECA Initial Comments at 16; NV Energy Initial Comments at 10; PPL Initial Comments at 9; Puget Sound Initial Comments at 5-6; Tri-State Initial Comments at 7-8.

rule.[466] Thus, contrary to comments from PPL,[467] we find that smaller transmission providers are able to provide this information to prospective interconnection customers and that the benefits outweigh the burdens.

159. In response to comments from the NY Commission and NYSERDA asking for flexibility to ensure that the information is accessible and understandable,[468] we do not think that such flexibility is needed—we specifically require the information to be contained within an interactive map and posted on transmission providers' websites for this purpose. Contrary to comments from NV Energy,[469] we find that the interactive map is necessary to ensure accessibility and understandability. Absent the map, potential interconnection customers would need to separately map injection points of interconnection to specific locations.

160. In response to comments from PJM and NV Energy requesting flexibility for transmission providers, in lieu of the heatmap, to post congestion information and a link to OASIS with interchange limits and schedules, we decline to grant such flexibility. We find that there are meaningful differences between the results of planning studies, such as those used in the interconnection process, and operational data, like congestion and

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[466] Environmental Defense Fund Reply Comments at 3-4 (citing Central Hudson Gas & Electric Corp., Solar PV Hosting Capacity Map, https://www.cenhud.com/en/my-energy/distributed-generation/solar-pv-hc-map/).

[467] PPL Initial Comments at 9.

[468] NY Commission and NYSERDA Initial Comments at 7.

[469] NV Energy Initial Comments at 10.

interchange schedules. Interconnection studies are generally conducted at a specific high-stress point in time for injection at a specific point of interconnection to determine flows across the whole transmission system, while operational data are simply the accumulation of real-time and/or day-ahead results. Thus, posting such operational data would only introduce timing differences and could not substitute for the deliverability analyses conducted in the interconnection processes.

161. In response to NYTOs, we clarify that the information displayed in the heatmap will be illustrative, non-binding, and subject to change.[470] We agree with Tri-State's statement that transmission providers must also caveat that the results do not account for affected system impacts. As we have acknowledged, one primary driver of the available interconnection capacity is the composition of the interconnection customer's cluster, and the heatmap cannot reflect those additional interconnection requests prior to the end of the customer request window.

162. In response to requests to clarify the funding mechanism associated with the heatmap requirement,[471] we clarify that transmission providers, not interconnection customers, are responsible for paying for costs associated with posting the relevant heatmaps required in *pro forma* LGIP section 6.1. However, we note that, to the extent such costs are properly recoverable in transmission rates consistent with existing

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[470] NYTOs Initial Comments at 9.

[471] National Grid Initial Comments at 8; PacifiCorp Initial Comments at 14; Tri-State Initial Comments at 7-8.

Commission accounting and ratemaking policy, such rate treatment is appropriate, and this final rule does not preclude such treatment. We find that this reform will improve overall interconnection queue efficiency to the benefit of transmission customers, consistent with Commission policy.[472]

163. In response to Dominion, which requests clarification in the RTO/ISO context,[473] we clarify that within an RTO/ISO, the heatmap requirement applies to the RTO/ISO, rather than to an individual transmission owner in an RTO/ISO. Thus, transmission owners in RTOs/ISOs are not required to separately post their own visual representations and results.

164. Finally, in response to concerns from WAPA about federal power marketing agencies having defined budgets and appropriations,[474] we note that transmission providers may explain specific circumstances on compliance and justify why any deviations are either "consistent with or superior to" the *pro forma* LGIP or merit an independent entity variation in the context of RTOs/ISOs.

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[472] Order No. 845, 163 FERC ¶ 61,043 at P 37.

[473] Dominion Initial Comments at 14.

[474] WAPA Initial Comments at 7-8.

2. Cluster Study Process

a. Need for Reform and Interconnection Study Procedures

i. NOPR Proposal

165. To remedy what may now be an unjust and unreasonable interconnection process, the Commission proposed to eliminate the serial first-come, first-served study process in the *pro forma* LGIP and instead require transmission providers to use a first-ready, first-served cluster study process.[475] The Commission explained that under a first-ready, first-served cluster study process, transmission providers would perform larger interconnection studies encompassing numerous proposed generating facilities, rather than separate studies for each individual interconnection request. Under the NOPR proposal, transmission providers would perform a single cluster study and cluster restudy each year, the particulars of which are further discussed below.

ii. Comments

166. Many commenters support the elimination of the serial study process and the use of the proposed cluster study process.[476] Several commenters assert that the proposed

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[475] NOPR, 179 FERC ¶ 61,194 at P 64.

[476] ACE-NY Initial Comments at 2; ACORE Initial Comments at 4; AEE Initial Comments at 10; AEE Reply Comments at 8; AEP Reply Comments at 3-4; AES Initial Comments at 9; Amazon Initial Comments at 2-3; Ameren Initial Comments at 6; APPA-LPPC Initial Comments at 14; Apple Initial Comments at 1; APS Initial Comments at 6; Avangrid Initial Comments at 10, 11; Avangrid Reply Comments at 4; Bonneville Initial Comments at 3; CAISO Initial Comments at 8; Clean Energy Associations Initial Comments at 19; Clean Energy Buyers Initial Comments at 8; Clean Energy States Initial Comments at 5; Colorado Commission Initial Comments at 8; Cypress Creek Initial Comments at 12; Dominion Initial Comments at 14; Duke Southeast Utilities Initial Comments at 1; Environmental Defense Fund Reply Comments at 6; EEI Initial

cluster study process will increase efficiency in the interconnection process by diminishing delays and backlogs in processing interconnection queues.[477] Several commenters also believe that the proposed cluster study process will result in fewer interconnection request withdrawals[478] and will discourage speculative interconnection

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Comments at 2, 5; EEI Reply Comments at 4-5; El Paso Electric Initial Comments at 4; NERC Initial Comments at 26; Enel Initial Comments at 11; EPSA Initial Comments at 5-6; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 12; Fervo Energy Initial Comments at 3; Fervo Energy Reply Comments at 3; Idaho Power Initial Comments at 1, 4; Illinois Commission Initial Comments at 7; Indicated PJM TOs Initial Comments at 10; Iowa Commission Initial Comments at 3; ISO-NE Initial Comments at 19; MISO Initial Comments at 28; NARUC Initial Comments at 6; National Grid Initial Comments at 3-4; Navajo Utility Initial Comments at 12; NESCOE Initial Comments at 9; NextEra Initial Comments at 13; Northwest and Intermountain Initial Comments at 2; NV Energy Initial Comments at 4; NY Commission and NYSERDA Initial Comments at 5; NYISO Initial Comments at 10-11; NYTOs Initial Comments at 7; Ohio Commission Consumer Advocate Initial Comments at 7; Omaha Public Power Initial Comments at 4; OMS Initial Comments at 7; OPSI Initial Comments at 3-4; Ørsted Initial Comments at 7; OSPA Reply Comments at 15; Pacific Northwest Utilities Initial Comments at 1; Pennsylvania Commission Initial Comments at 5-6; Pine Gate Initial Comments at 14; PJM Initial Comments at 16; Public Interest Organizations Initial Comments at 25; Puget Sound Initial Comments at 4, 5; R Street Initial Comments at 8; SDG&E Initial Comments at 2; SEIA Initial Comments at 7; SoCal Edison Initial Comments at 3; State Agencies Initial Comments at 2, 12; Tesla Initial Comments at 1; Tri-State Initial Comments at 3; U.S. Chamber of Commerce Initial Comments at 6; UMPA Initial Comments at 2; WAPA Initial Comments at 8; WIRES Initial Comments at 5.

[477] AEP Initial Comments at 16; Amazon Initial Comments at 2-3; Apple Initial Comments at 1; Consumers Energy Initial Comments at 4; Environmental Defense Fund Initial Comments at 5; EEI Initial Comments at 2, 5; ELCON Initial Comments at 2, 8; EPSA Initial Comments at 6; Idaho Power Initial Comments at 4; Indicated PJM TOs Initial Comments at 10; NV Energy Initial Comments at 4; Ohio Commission Consumer Advocate Initial Comments at 8; Pennsylvania Commission Initial Comments at 5-6; Pine Gate Initial Comments at 14; Public Interest Organizations Initial Comments at 25; SEIA Initial Comments at 7; WIRES Initial Comments at 6.

[478] AEP Initial Comments at 16; Dominion Initial Comments at 14; ELCON Initial Comments at 9; EPSA Initial Comments at 7; Ohio Commission Consumer Advocate

requests.[479] Some commenters assert that, from the interconnection customer's perspective, the proposed cluster study process provides more certainty on timing and cost.[480] Several commenters state that they have already implemented some of the proposed cluster study process reforms.[481]

167. Dominion states that another benefit of moving to the proposed cluster study process is that, if a proposed generating facility is not ready for its cluster study, it can join the next cluster rather than losing its interconnection queue position as occurs in a serial study process.[482] Dominion asserts that, as a result, the proposed cluster study process removes the incentive for an interconnection customer to "reserve a spot in line" for a proposed generating facility is not yet viable. Ohio Commission Consumer Advocate believes that larger interconnection studies encompassing numerous proposed generating facilities would be especially beneficial for interconnection customers with multiple proposed generating facilities in close geographical proximity.[483] Avangrid

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Initial Comments at 8; SEIA Initial Comments at 7.

[479] Clean Energy States Initial Comments at 5; Colorado Commission Initial Comments at 8; ELCON Initial Comments at 9; EPSA Initial Comments at 6; SoCal Edison Initial Comments at 3-4.

[480] Avangrid Initial Comments at 11; Dominion Initial Comments at 14.

[481] APS Initial Comments at 6; Duke Southeast Utilities Initial Comments at 2; MISO Initial Comments at 28; PacifiCorp Initial Comments at 16; SPP Initial Comments at 5.

[482] Dominion Initial Comments at 15.

[483] Ohio Commission Consumer Advocate Initial Comments at 8.

believes that applying this concept to more regions will lead to a more guided and proactive build-out of new generation and required transmission upgrades.[484]

168. Several commenters argue that the proposed cluster study process will foster renewable resource development and aid in meeting national and/or state clean energy and carbon emissions reduction goals.[485] Puget Sound states that over the past year, it has seen unprecedented numbers of interconnection requests in response to the resource solicitation process and a demand for new renewable energy sources.[486] Puget Sound adds that it has experienced a backlogged interconnection queue, entry of speculative interconnection requests, and uncertainty for interconnection customers relying on higher-queued interconnection requests to complete the interconnection process for their proposed generating facilities to be feasible. Clean Energy States assert that, because wind and solar projects can be relatively small, clustering should help smaller projects share the cost of interconnection studies and upgrades, thereby providing them a viable path through the interconnection process.[487]

169. Some commenters support the use of the proposed cluster study process, so long as it is coupled with additional requirements, some of which the Commission proposed in

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[484] Avangrid Initial Comments at 11.

[485] Apple Initial Comments at 1; Navajo Utility Initial Comments at 12; SoCal Edison Initial Comments at 4; State Agencies Initial Comments at 12.

[486] Puget Sound Initial Comments at 4-5.

[487] Clean Energy States Initial Comments at 5.

the NOPR.[488] AEE recommends that the Commission consider further reforms to harmonize study assumptions and more closely link generator interconnection and long-term regional transmission planning processes.[489] R Street states that the Commission should consider an interconnection study approach that uses transparent, realistic study assumptions.[490] Clean Energy Associations argue that certain conservative assumptions—such as NERC standard TPL-001's extreme contingency cases—can lead to the identification of unreasonably large and costly upgrades.[491] Clean Energy Associations also assert that the Commission should make clear in its final rule whether moving from a serial study process to a cluster study process should or should not be accompanied by any change in the interconnection standards and assumptions used in those studies.[492] Ameren generally supports the proposal to move to a first-ready, first-served cluster study process, but argues that this move without other reforms is unlikely to clear the interconnection queue backlog.[493] NERC states that its support for cluster

[488] AEP Initial Comments at 6, 16; Ameren Initial Comments at 6; Cypress Creek Initial Comments at 12; CREA and NewSun Initial Comments at 10, attach. A; CREA and NewSun Reply Comments at 8; Enel Initial Comments at 11; Eversource Initial Comments at 13; Invenergy Initial Comments at ii; NRECA Initial Comments at 8, 18; PPL Initial Comments at 10; SoCal Edison Initial Comments at 4.

[489] AEE Initial Comments at 10.

[490] R Street Reply Comments at 2.

[491] Clean Energy Associations Initial Comments at 28.

[492] *Id.* at 21.

[493] Ameren Initial Comments at 6.

studies is predicated on parallel enhancements for model validation with actual installed equipment and a true-up prior to interconnection.[494]

170. Other commenters express some concern with the move to the proposed cluster study process. For example, Enel states that cluster studies increase interdependence between interconnection requests, with a greater likelihood that multiple interconnection customers are responsible for a single network upgrade, which creates a paradigm where one interconnection customer's actions, such as withdrawing from the interconnection queue, can have drastic impacts on many other interconnection customers.[495] Enel also asserts that, while the proposed cluster study process has some benefits, recent cluster studies are resulting in significant regional transmission constraints with very high associated network upgrade costs and long construction schedules. Enel contends that the proposed cluster study process can still reduce interdependency and succeed if there are much smaller, more local, regional groupings of interconnection requests in cluster studies and lower minimum impact thresholds for determining network upgrades. Enel says the Commission should adopt these two practices if it adopts the proposed cluster study process.

171. Some commenters note that, where the demand for generator interconnection significantly exceeds the available supply of interconnection access, the NOPR's proposed cluster study process and interconnection queue management reforms alone

[494] NERC Initial Comments at 26.

[495] Enel Initial Comments at 12-13.

may be insufficient to address the backlog of interconnection requests.[496] Other commenters assert that under these circumstances, some form of interconnection request prioritization may be needed to effectively allocate scarce interconnection access to the lowest-cost or highest-value proposed generating facilities.[497]

172. Several commenters state that, while they support the use of the proposed cluster study process, the Commission should allow variation among transmission providers in the makeup of the study process.[498] Some commenters argue that regional variations should be permitted, especially where transmission providers have already implemented a first-ready, first-served cluster study process.[499] Environmental Defense Fund, on the other hand, argues that the Commission should provide limited flexibility for transmission providers to demonstrate in their compliance filing that a preexisting cluster

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[496] AEE Reply Comments at 8; Cypress Creek Initial Comments at 12.

[497] NARUC Initial Comments at 11-12; Western Regulators Initial Comments at 1.

[498] AEP Initial Comments at 16; APPA-LPPC Initial Comments at 14; Avangrid Initial Comments at 10; Dominion Initial Comments at 14; EEI Initial Comments at 5; Eversource Initial Comments at 13; NARUC Initial Comments at 6-7; NEPOOL Initial Comments at 14; NRECA Initial Comments at 18-19; Omaha Public Power Initial Comments at 4; OMS Initial Comments at 8.

[499] AEP Initial Comments at 16; APPA-LPPC Initial Comments at 14; Idaho Power Initial Comments at 4; Indicated PJM TOs Initial Comments at 10-11, 16; MISO Initial Comments at 31-32; NextEra Reply Comments at 7; NYISO Initial Comments at 10-11; Pacific Northwest Utilities Initial Comments at 2; SoCal Edison Initial Comments at 4; U.S. Chamber of Commerce Initial Comments at 6-7; WIRES Initial Comments at 6-7.

study process is substantially similar to the process established in the Commission's final rule.[500]

173. Pacific Northwest Utilities and CREA and NewSun urge the Commission to allow flexibility for transmission providers to design the cluster study process to implement either a single-phase or two-phase cluster study process.[501] Pacific Northwest Utilities contend that requiring full commercial readiness in a single-phase study process, as proposed in the NOPR, significantly restricts an interconnection customer's ability to enter the interconnection queue.[502] Pacific Northwest Utilities argue that a two-phase approach provides greater accessibility to some interconnection customers by not requiring commercial readiness for entry into the first phase. According to Pacific Northwest Utilities, this is because all interconnection customers who have attained site control will have information about the network upgrades needed to meet the interconnection requirements of the cluster and the expected cost responsibility for each interconnection customer in the cluster. Pacific Northwest Utilities aver that this information reduces the potential for interconnection customers to withdraw from phase two and, therefore, should reduce the need for additional restudies that might slow or stall the interconnection process.

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[500] Environmental Defense Fund Reply Comments at 7.

[501] CREA and NewSun Reply Comments at 12-13; Pacific Northwest Utilities Initial Comments at 6, 8-9.

[502] Pacific Northwest Utilities Initial Comments at 7-8.

174. Some commenters argue that it may not be appropriate to mandate the proposed cluster study process for every transmission provider as cluster studies can be complex, expensive, and not the most efficient or necessary approach for all proposed generating facilities or circumstances.[503] Some commenters generally support the use of cluster studies if transmission providers retain discretion to use the existing serial study process.[504] Vermont Electric and Vermont Transco notes that not all interconnection requests need to be studied in a cluster format, and that this has frequently been the situation in New England, where interconnection queue bottlenecks have historically been locational and driven by state clean energy procurement efforts.[505] ISO-NE requests that the Commission consider a more targeted approach for clusters triggered by geographic or electric proximity among interconnection requests, rather than a blanket clustering process for all interconnection requests.[506] Instead of mandating a clustering in all regions, ISO-NE contends that the Commission consider the expanded use of clustering in areas with larger concentrations of proposed generating facilities, while

[503] SPP Initial Comments at 5.

[504] AECI Initial Comments at 5; AEP Reply Comments at 4; Avangrid Reply Comments at 4-5; CREA and NewSun Initial Comments at 44; ELCON Initial Comments at 9; NextEra Initial Comments at 15; Southern Initial Comments at 6; Vermont Electric and Vermont Transco Initial Comments at 2-3.

[505] Vermont Electric and Vermont Transco Initial Comments at 2.

[506] ISO-NE Initial Comments at 24.

allowing use of serial studies for customers seeking to interconnect in areas with low activity, where serial studies could proceed relatively quickly.

175. National Grid asks for clarification as to whether the proposed cluster study process encompasses energy or capacity interconnection service requests, or both.[507]

176. Some commenters contend that the Commission should encourage relevant state entities to consider the efficient coordination of their state-jurisdictional interconnection process with Commission-jurisdictional interconnection processes.[508] Avangrid argues that sizable distributed energy resources should be aggregated and included in the broader cluster study of large and small Commission-jurisdictional generating facilities. Pine Gate suggests the Commission require transmission providers, on compliance, to "document how they will ensure that any serial processes for state-jurisdictional interconnection agreements will interact with the required cluster study process" and explain how the interconnection queue position of qualifying facilities (QFs) will not be prejudiced by the transition to a cluster study process.[509]

iii. <u>Commission Determination</u>

177. We adopt the NOPR proposal to revise the *pro forma* LGIP and *pro forma* LGIA to make cluster studies the required interconnection study method. We find that the move from the serial study process in the *pro forma* LGIP to the proposed cluster study

[507] National Grid Initial Comments at 16.

[508] Avangrid Initial Comments at 12.

[509] Pine Gate Initial Comments at 15.

process, alongside the other reforms adopted in the final rule, will remedy the unjust and unreasonable rates discussed in Section II of this final rule. Specifically, we believe that this reform will help remedy the problems of the existing interconnection process for large generating facilities in several ways. First, the cluster study process will increase efficiency because transmission providers can perform larger interconnection studies encompassing many proposed generating facilities, rather than separate studies for each individual interconnection customer.[510] The cluster study process will provide greater certainty to interconnection customers, regarding both the timing of studies and the magnitude of network upgrade costs. Coupled with the increased financial commitments and requirements to enter the interconnection queue, such as a demonstration of site control, as discussed further below, the cluster study process will also disincentivize interconnection customers from submitting interconnection requests for speculative generating facilities and ensure that ready, more viable proposed generating facilities can

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[510] NOPR, 179 FERC ¶ 61,194 at P 64; May Joint Task Force Tr. 46:15-19 (Clifford Rechtschaffen) (stating that CAISO's cluster process has been helpful and important for improving interconnection queue processing and that clustering "is a best practice and should be promoted"); EEI Initial Comments at 2, 5; ELCON Initial Comments at 2, 8; EPSA Initial Comments at 6; Idaho Power Initial Comments at 4; Indicated PJM TOs Initial Comments at 10; Pennsylvania Commission Initial Comments at 5-6; *see also* May Joint Task Force Tr. 43:25-44:4 (Riley Allen) ("Clustering helps the regions identify what I'll call the backbone or trunk facilities that provide efficiencies in the system to the benefit ultimately of ratepayers. New England has been relying on clustering and I'm told that that's going very well."); 42:3-9 (Gladys Brown Dutrieuille) (explaining that clustering has two goals: minimizing the study time and minimizing the first mover disadvantage by sharing costs among those resources that need the same upgrades).

proceed through the study process.[511] We also expect that the cluster study process will result in fewer withdrawals because conducting a single cluster study and cluster restudy will minimize delays that arise from proposed generating facility interdependencies under the existing serial study process, in which lower-queued interconnection customers can strategically and monetarily benefit from network upgrades and associated costs borne earlier in the interconnection process by higher-queued interconnection customers. We further expect that the cluster study process will minimize the risk of cascading restudies when an interconnection customer withdraws.[512]

178. We are not persuaded by Enel's request that the Commission adopt smaller, more local regional groupings of proposed generating facilities in interconnection studies and lower minimum impact thresholds for determining upgrades.[513] We find the record insufficient to support these additional requirements. We also decline requests to allow transmission providers to either continue to use a serial study process or to create a parallel serial study process[514] because, as discussed further below, we find that

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[511] ELCON Initial Comments at 9; EPSA Initial Comments at 6; NYTOs Initial Comments at 7; Ohio Commission Consumer Advocate Initial Comments at 8; SoCal Edison Initial Comments at 4; State Agencies Initial Comments at 12.

[512] Cypress Creek Initial Comments at 12; Dominion Initial Comments at 14; SEIA Initial Comments at 7.

[513] Enel Initial Comments at 13.

[514] AECI Initial Comments at 5; AEP Reply Comments at 4; Avangrid Reply Comments at 4-5; CREA and NewSun Initial Comments at 44; ELCON Initial Comments at 9; SPP Initial Comments at 5; Vermont Electric and Vermont Transco Initial Comments at 2-3.

establishing in the *pro forma* LGIP a separate interconnection process outside the cluster study process could detract from transmission providers' efforts to efficiently process cluster studies, and would be insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

179. In response to requests to allow variation in how clusters are formed,[515] we emphasize that the reforms to the *pro forma* LGIP adopted in this final rule do not prescribe how transmission providers should form clusters.

180. In response to National Grid,[516] we decline to clarify whether the proposed cluster study process encompasses energy or capacity interconnection service requests. "Energy interconnection requests" and "capacity interconnection requests" are not defined terms in the *pro forma* LGIP, and we decline to define them here. We do not believe that such detail is needed for transmission providers to implement the reforms adopted herein.

181. In response to Avangrid,[517] we encourage relevant state entities to consider the efficient coordination of their state-jurisdictional interconnection processes with Commission-jurisdictional interconnection processes.

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[515] Clean Energy States Initial Comments at 10; CREA and NewSun Reply Comments at 12-13; Pacific Northwest Utilities Initial Comments at 6-9; R Street Initial Comments at 11.

[516] National Grid Initial Comments at 16.

[517] Avangrid Initial Comments at 12.

182. In response to requests to create some form of generating facility prioritization,[518] we are neither persuaded that such prioritization is needed, nor do we have an adequate record to dictate how generating facility prioritization should be implemented in a just, reasonable, and not unduly discriminatory or preferential manner.

183. Finally, we decline to adopt the following proposals advocated by some commenters because they are outside the scope of this proceeding: (1) AEE's request that the Commission consider further reforms to more closely link generator interconnection and long-term regional transmission planning process;[519] (2) Cypress Creek's request to require transmission providers to allow interconnection customers to seek energy-only injection as a default and provide a subsequent process (needed to address capacity-market constructs) by which an interconnection customer can add firm rights;[520] (3) Pine Gate's suggestion for the Commission to require transmission providers to document on compliance how they will ensure that any serial study processes for state-jurisdictional interconnection agreements will interact with the required cluster study process and explain how the interconnection queue position of QFs will not be prejudiced by the transition to a cluster study process;[521] and (4) AEE's and

[518] AEE Reply Comments at 8; Cypress Creek Initial Comments at 12; NARUC Initial Comments at 11-12; Western Regulators Initial Comments at 1.

[519] AEE Initial Comments at 10.

[520] Cypress Creek Initial Comments at 8-9.

[521] Pine Gate Initial Comments at 15.

Clean Energy Associations' request that the Commission also harmonize study standards and assumptions.[522] We find that these proposals are outside the scope of this proceeding as the Commission did not propose specific reforms on these issues, and we find an inadequate record to fully consider or adopt these requested changes.

b. Defined Terms in the *Pro Forma* LGIP and *Pro Forma* LGIA

i. NOPR Proposal

184. In the NOPR, the Commission proposed to add several new defined terms (such as cluster, cluster study process, and cluster request window) and to revise several defined terms (such as stand alone network upgrade and material modification) in section 1 of the *pro forma* LGIP and article 1 of the *pro forma* LGIA.[523]

ii. Comments

185. Starting with the proposed definition of stand alone network upgrade, a few commenters support the Commission's proposal.[524] Tri-State suggests adding to the definition of stand alone network upgrade that a transmission provider's interconnection facilities may be shared by more than one generating facility in a given cluster study, including a co-located resource.[525]

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[522] AEE Initial Comments at 10; Clean Energy Associations Initial Comments at 21, 28.

[523] NOPR, 179 FERC ¶ 61,194 at P 65.

[524] Ameren Initial Comments at 9; MISO Initial Comments at 32.

[525] Tri-State Initial Comments at 25.

186. Other commenters oppose the proposed revisions to the definition of stand alone network upgrade. Clean Energy Associations argue that the proposal to modify the definition of stand alone network upgrade to restrict it to those needed only for a single interconnection customer is problematic and counterproductive.[526] Clean Energy Associations contend that allowing interconnection customers the right to self-build interconnection facilities and stand alone network upgrades since Order No. 845 has served as a welcome relief valve to transmission providers' lengthy construction timelines, giving customers increased control of both the time and cost for building these upgrades. As an alternative, Clean Energy Associations suggest an approach similar to ISO-NE's for network upgrades that are needed for multiple interconnections where an independently developed elective network upgrade, if selected by all of the interconnection customers in the cluster that require the network upgrade, can take the place of the incumbent-built cluster enabling network upgrade.

187. Pine Gate states that in its experience, after Order No. 845, transmission providers have taken a very narrow view of the facilities that constitute stand alone network upgrades, and thus the potential for interconnection customers to exercise the option to build has not been fully realized.[527] Pine Gate asserts that the proposed change would further restrict the opportunity for interconnection customers to exercise the option to

[526] Clean Energy Associations Initial Comments at 22-23.

[527] Pine Gate Initial Comments at 63-64 (citing Comments of Pine Gate, Docket No. RM21-17-000, at 9-10 (filed Oct. 12, 2021); Order No. 2003, 104 FERC ¶ 61,103 at PP 85, 353).

build, exacerbate construction delays, and result in a lack of competition to construct stand alone network upgrades, ultimately harming consumers. Pine Gate therefore recommends that the Commission not modify the definition of stand alone network upgrade as proposed and instead grant the interconnection customer with the largest projected impact on a potential stand alone network upgrade facility the ability to elect the option to build with priority falling to each interconnection customer based on the next largest impact on the stand alone network upgrades.

188. Enel argues that the Commission should not adopt the proposed substantive revisions to the definition of stand alone network upgrades and should instead expand the definition of stand alone network upgrades to include upgrades to an existing transmission facility which involves a transmission line or substation being entirely rebuilt.[528] Enel offers suggestions for implementing a third-party option that would give interconnection customers more control over the cost and schedule of larger network upgrades, resolving a frequent barrier to bringing needed generating facilities online. To that end, Enel states that *pro forma* LGIA article 5.1 could be modified to specify that the option to build is only eligible for stand alone network upgrades funded by a single interconnection customer, while the proposed third-party option could be used for all stand alone network upgrades, including line and substation rebuilds.

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[528] Enel Initial Comments at 55-56.

189. Moving to the proposed definition of material modification, some commenters support the Commission's proposal.[529] Ørsted urges the Commission to ensure that under the newly proposed definition of material modification, any changes to a proposed generating facility that occur on the generating facility side of the point of interconnection that do not result in changes to the electrical output at the point of interconnection or the electrical characteristics of the generating facility's interconnection: (1) will not be deemed to be a material modification; and (2) will not result in the termination of the interconnection customer's queue position.[530]

190. Ameren suggests that the Commission consider clarifying the proposed definition of material modification, so that cost and timing are factors to be considered in addition to when the transmission provider determines changes to the point of interconnection are otherwise material (e.g., from an electrical standpoint).[531] Ameren states that the Commission may want to consider whether the change should only be triggered by a change to the point of interconnection or whether a change to the inverters or other pieces of equipment in the interconnecting generating facility, which could require other upgrades, should also result in the determination of a material modification.

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[529] Ameren Initial Comments at 9; MISO Initial Comments at 32.

[530] Ørsted Initial Comments at 8.

[531] Ameren Initial Comments at 9.

191. EPSA asks the Commission to be clearer in determining a standard definition of a material modification.[532] EPSA argues that, at minimum, the Commission should direct each RTO/ISO or each NERC region to establish clear criteria for the evaluation of material modifications.

iii. <u>Commission Determination</u>

192. We adopt the proposed revisions to section 1 of the *pro forma* LGIP and article 1 of the *pro forma* LGIA to revise and add several defined terms. Specifically, we adopt the proposed revisions to the definition of stand alone network upgrade to clarify that, for a network upgrade to be eligible for treatment as a stand alone network upgrade, the network upgrade must be required for only one interconnection customer and must meet the other existing requirements in the definition of stand alone network upgrade. We address further modifications to the definition of stand alone network upgrade below where discussing network upgrade cost allocation (Section III.A.4.c of this final rule). We also adopt the proposed revisions to the definition of material modification, which account for the equal interconnection queue position of proposed generating facilities that are part of the same cluster. We also modify the NOPR proposal to define interconnection facilities study report.

193. With respect to the definition of stand alone network upgrade, in response to Clean Energy Associations' concerns, we note that we do not remove the right to self-build interconnection facilities and stand alone network upgrades established in Order No. 845.

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[532] EPSA Initial Comments at 13.

Rather, we are explicitly maintaining the status quo, which is to say that, under the existing *pro forma* LGIP, there is no potential for a stand alone network upgrade to be shared by more than one interconnection customer. With the revision proposed in the NOPR and adopted here, we are ensuring that within the structure of a cluster study process adopted in this final rule, stand alone network upgrades continue to be defined as only those required for a single interconnection customer, and therefore the option to build is only available for a single interconnection customer. Were we to not adopt this revision, multiple interconnection customers could potentially attempt to construct the same stand alone network upgrades, leading to confusion and potentially lengthy negotiations and/or disputes regarding which interconnection customer had the right to construct the stand alone network upgrade. Additionally, with regard to Clean Energy Associations' request that the Commission consider an approach similar to ISO-NE's for certain upgrades that are needed for multiple interconnections, we decline to adopt this approach because it is outside the scope of this proceeding. We are not proposing in this proceeding to modify the *pro forma* LGIP to address the cost responsibility and division of work between interconnection customers that may share cost allocation for stand alone network upgrades.

194. Similarly, Tri-State, Pine Gate, and Enel argue that the Commission should expand the definition of stand alone network upgrade, thereby expanding the right of interconnection customers to build certain network upgrades. These requests are outside the scope of this proceeding, which is not proposing to modify the scope of interconnection customers' option to build certain stand alone network upgrades but

rather is only revising definitions insofar as is necessary to implement reforms adopted elsewhere in this final rule. For the same reason, we decline to expand the definition of material modification, as Ørsted, Ameren, and EPSA request.[533]

c. Definitive Point of Interconnection

i. NOPR Proposal

195. In the NOPR, the Commission proposed to add new section 3.1.2 to the *pro forma* LGIP and therein to require interconnection customers to select a definitive point of interconnection to be studied no later than the execution of the cluster study agreement. The Commission also proposed that, upon mutual agreement, the transmission provider may make reasonable changes to the requested point of interconnection to facilitate efficient generator interconnection of clustered interconnection requests at common points of interconnection.[534]

ii. Comments

196. MISO supports the Commission requiring the selection of a definitive point of interconnection when executing the cluster study agreement; however, MISO encourages the Commission to require the selection of a definitive point of interconnection even earlier, as part of the interconnection request.[535] MISO notes that requiring an earlier

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[533] *See* Ameren Initial Comments at 9; EPSA Initial Comments at 13; Ørsted Initial Comments at 8.

[534] NOPR, 179 FERC ¶ 61,194 at P 66.

[535] MISO Initial Comments at 33-34.

selection of the definitive point of interconnection will assist in interconnection queue processing, as a transmission provider would not be able to begin modeling work if the interconnection customer is permitted to wait until a later point in time to select its definitive point of interconnection. MISO further argues that the definitive point of interconnection (even if subject to change) should be selected prior to any scoping meeting. MISO also supports the proposed language that limits the ability of the interconnection customer to change its point of interconnection after the submission of interconnection request.

197. Other commenters do not support the Commission's proposal to require a definitive point of interconnection when executing the cluster study agreement.[536] ACE-NY supports making the demonstration of a feasible point of interconnection a requirement for a generating facility to move into the facilities study phase of the generator interconnection process.[537]

198. Pine Gate and CREA and NewSun assert that the Commission should modify its proposal to permit interconnection customers to request alternative points of interconnection.[538] Pine Gate argues that the Commission should permit interconnection customers to request a study of a primary and secondary point of interconnection within

[536] ACE-NY Initial Comments at 3; CREA and NewSun Initial Comments at 47; Pine Gate Initial Comments at 15.

[537] ACE-NY Initial Comments at 3-4.

[538] CREA and NewSun Initial Comments at 47-48; Pine Gate Initial Comments at 15-16.

one or two electrical buses, then select a point of interconnection restudy after receiving initial cluster study results.[539] Similarly, CREA and NewSun assert that the Commission should permit alternative points of interconnection, and collective points of interconnection for proposed generating facilities in a cluster (e.g., those that could connect to a single substation), to be proposed and studied, at least through the system impact study in order to obtain more complete cost information.[540]

199. Enel suggests that, in the second paragraph of proposed section 3.1.2 of the *pro forma* LGIP, the Commission should change the word "make" to "propose" in the following quoted language: "For purposes of clustering Interconnection Requests, Transmission Provider may make reasonable changes to the requested Point of Interconnection."[541] Enel explains that this would clarify that any such changes can only be made with the consent of the interconnection customer, as specified in the proposed new final sentence to that paragraph.

iii. <u>Commission Determination</u>

200. We adopt the proposed section 3.1.2 of the *pro forma* LGIP insofar as it requires an interconnection customer to select a definitive point of interconnection to be studied when executing the cluster study agreement, with one modification discussed below.

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[539] Pine Gate Initial Comments at 15-16.

[540] CREA and NewSun Initial Comments at 47-48.

[541] Enel Initial Comments at 82.

201. Requiring interconnection customers to select a definitive point of interconnection when executing the cluster study agreement allows the interconnection customer to submit its interconnection request with a proposed point of interconnection, participate in the scoping meeting during the customer engagement window, and receive feedback on its proposed point of interconnection. We believe that this strikes the right balance between allowing for flexibility and potential adjustments to the point of interconnection, based on discussion with the transmission provider and the transmission provider's detailed knowledge of its transmission system, and providing transmission providers with the information necessary to conduct the cluster study, thus reducing the potential for restudies that would be required if interconnection customers could change their points of interconnection later in the process.

202. We decline to: (1) require that the definitive point of interconnection be selected earlier (e.g., as part of the interconnection request);[542] (2) only require that the definitive point of interconnection be selected later (e.g., at the facilities study phase);[543] or (3) permit interconnection customers to submit multiple alternative points of interconnection for study in a single interconnection request.[544] We believe that requiring the selection of a definitive point of interconnection earlier in the cluster study process, as suggested by

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[542] *See* MISO Initial Comments at 33.

[543] *See* ACE-NY Initial Comments at 3-4.

[544] *See* CREA and NewSun Initial Comments at 47-48; Pine Gate Initial Comments at 15-16.

MISO, would deprive interconnection customers of information that could aid in their selection. Similarly, we believe that requiring the selection of a definitive point of interconnection after the cluster study, as suggested by ACE-NY, or allowing multiple points of interconnection to be studied before the interconnection customer is required to select the definitive point of interconnection, as suggested by Pine Gate and CREA and NewSun, fails to take into account the fact that, if an interconnection customer changes the definitive point of interconnection after the cluster study, it will likely impact the study results of the other interconnection customers in the cluster and could lead to restudies and delays. We do not believe that the alternatives suggested by commenters would remedy the unjust and unreasonable status quo described in Section II of this final rule.

203. Finally, we agree with Enel's suggestion to change the word "make" to "propose" in *pro forma* LGIP section 3.1.2. We modify that section to state: "For purposes of clustering Interconnection Requests, Transmission Provider may propose reasonable changes to the requested Point of Interconnection."[545] We agree that this clarifies that any such changes can only be made with the consent of the interconnection customer.

[545] Enel Initial Comments at 82.

d. Cluster Request Window and Customer Engagement Window

i. NOPR Proposal

204. In the NOPR, the Commission proposed to add new section 3.4.1 (Cluster Request Window) to the *pro forma* LGIP to require interconnection customers to submit an interconnection request during the cluster request window—a 45-calendar day period with the start date to be determined by each transmission provider (with the annual start date for the transmission provider's cluster request window included in its LGIP).[546] The transmission provider would consider all interconnection requests accepted during this period to have equal queue priority for purposes of the cluster study. The Commission also proposed to add in *pro forma* LGIP section 3.1.1 (Initial Study Deposit) a non-refundable application fee of $5,000 to be submitted with the interconnection request. The Commission further proposed that interconnection customers must cure deficient interconnection requests within 10 business days after receipt of notice from the transmission provider, but no later than the close of the cluster request window.

205. The Commission also proposed to add new *pro forma* LGIP section 3.4.5 (Customer Engagement Window), which provides that, following the close of the cluster request window, the transmission provider begins a 30-calendar day customer engagement window.[547] New *pro forma* LGIP section 3.4.5 also requires the

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[546] NOPR, 179 FERC ¶ 61,194 at P 67.

[547] *Id.*

transmission provider to post within the first 10 business days following the close of the cluster request window a list of interconnection requests for that cluster.

ii. Comments

206. Clean Energy Associations support the proposal to require interconnection customers to submit interconnection requests during the cluster request window.[548] MISO supports the Commission requiring a definitive application deadline as part of the implementation of cluster studies, and equal interconnection queue priority for all interconnection requests submitted prior to that deadline, but does not see an intrinsic value in a defined application start time.[549] MISO supports granting interconnection customers flexibility to submit an interconnection request earlier than the beginning of a cluster request window. Noting that, under proposed *pro forma* LGIP section 3.4.5, interconnection requests that are deemed valid during the customer engagement window are placed into the cluster study, Southern proposes that if an interconnection request is not deemed valid, the interconnection request should be withdrawn from the interconnection queue.[550]

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[548] Clean Energy Associations Initial Comments at 19.

[549] MISO Initial Comments at 35 (noting that, under the MISO tariff, all interconnection requests received after the application deadline "shall be applied towards the following Definitive Planning Phase cycle") (citing MISO, FERC Electric Tariff, attach. X, § 3.3.1 (158.0.0)).

[550] Southern Initial Comments at 37.

207. MISO expresses concern that the timelines listed in the customer engagement window for posting information are impractical.[551] MISO asserts that the Commission should not require a posting so near to the close of the cluster request window because the transmission provider must devote its resources to reviewing the interconnection requests for deficiencies.[552] MISO contends that this information would only be useful at this time to interconnection customers with speculative interconnection requests that may be trying to determine if their proposed generating facility is economically viable and that may be trying to identify a point of interconnection change to increase the viability of their interconnection requests.

208. MISO argues that the Commission should not require any informational posting pertaining to an interconnection request prior to the interconnection customer's finalization of the interconnection request because a definitive point of interconnection has not yet been selected.[553] MISO highlights that the proposed *pro forma* LGIP section 3.4.5 requires the transmission provider's OASIS posting to include "(3) the station or transmission line where the interconnection will be made."[554] However, MISO notes that an interconnection customer is not required to select a definitive point of interconnection

[551] MISO Initial Comments at 36.

[552] *Id.* (stating that a majority of its interconnection requests are submitted on the last day of the application window, or two days prior at most).

[553] *Id.* at 36-37.

[554] *Id.* at 37.

until the end of the customer engagement window. As such, MISO contends that the posting requirement is impossible if the transmission provider is required to post the point of interconnection. MISO argues that the Commission should not require any posting until a reasonable period after the interconnection customer is required to select its definitive point of interconnection and the information is complete, such as when the customer engagement window is completed and cluster studies are about to begin.

209. Regarding the makeup of the cluster, Clean Energy States assert that the cluster study process should allow for changes in the makeup of the cluster, and that the study process may identify ways to improve a cluster to provide better performance for the transmission system, such as by adding or subtracting certain interconnection requests from the cluster.[555] Clean Energy States assert that a transmission provider should be able to modify the cluster in response to interconnection customer changes or study findings without threatening the interconnection customer's queue priority or paying penalties.

210. EPSA argues that the final rule should specify that transmission providers are required to work with interconnection customers during the customer engagement window and study agreement negotiation in a manner that is fair and equitable regarding the study models to be used, data verification, and stakeholder engagement—regardless

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[555] Clean Energy States Initial Comments at 8-9.

of the planning or procurement method used by the prospective interconnection customer.[556]

211. Enel recommends that the Commission consolidate the interconnection request and cluster and facilities study agreements into a single study agreement to be submitted at the time of application.[557] Enel also recommends that the Commission include language in the *pro forma* LGIP that provides that transmission providers will not post information about interconnection requests proceeding through or withdrawing from the interconnection queue until all interconnection requests submitted within a cluster request window successfully meet their milestone requirements to proceed, withdraw, or fail to cure their breach within the specific cure period.[558]

212. Regarding the length of the cluster request window, some commenters support the proposed 45-calendar day time frame for the cluster request window.[559] Although it supports the 45-calendar day time frame, Eversource suggests the Commission add more structure to this element of its proposal by establishing rules that enable potential

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[556] EPSA Initial Comments at 7.

[557] Enel Initial Comments at 13.

[558] *Id.* at 48.

[559] Eversource Initial Comments at 13; Clean Energy Associations Initial Comments at 19.

interconnection customers to be informed of when the request windows will be open and how to prepare to apply.[560]

213. Other commenters argue that the proposed 45-calendar day time frame for the cluster request window is too short and should be increased to 60 calendar days.[561] ISO-NE states that, based on its experience implementing its forward capacity market process, each of the cluster study windows proposed in the NOPR should be extended to help ensure an efficient cluster study process.[562] Pine Gate also argues that a longer cluster request window would reduce the burden on transmission providers by providing more time to administer their deficiency notice processes.[563] Pine Gate explains that, for larger interconnection customers that may be developing numerous interconnection requests for multiple transmission providers, overlapping cluster request windows are likely. Additionally, Pine Gate contends that, as contemplated by the NOPR, it is likely that increased requirements and additional information for interconnection customers will be

[560] Eversource Initial Comments at 13.

[561] ISO-NE Initial Comments at 22-23; Pine Gate Initial Comments at 16; PJM Initial Comments at 19-20.

[562] ISO-NE Initial Comments at 22. ISO-NE requests that the Commission consider the following windows for the cluster study process: (i) cluster request window – 60 calendar days; (ii) customer engagement window – 90 calendar days; (iii) cluster study – 270 to 365 calendar days (depending on the size of a given cluster); (iv) cluster restudy – 150 calendar days; and (v) facilities study – 90 to 180 calendar days. *Id.* at 23.

[563] Pine Gate Initial Comments at 16.

due at the time of interconnection queue entry (e.g., the complex modeling required to be submitted) and burdensome to accommodate in the proposed time frame.

214. On the other hand, some commenters argue that a shorter cluster request window is appropriate. CAISO argues that longer cluster request windows result in low quality requests because interconnection customers have more time within the window to fix their submissions.[564] CAISO contends that its use of a shorter 15-day interconnection request completeness window followed by a longer validation and scoping meeting window have significantly improved interconnection request quality and the speed with which CAISO processes requests.[565] Similarly, Tri-State recommends that the cluster request window be shortened because, based on its experience, most interconnection requests submitted in the cluster request window are received the last two days of the request window.[566]

215. Regarding the requirement for correcting deficiencies in the proposed *pro forma* LGIP section 3.4.4 (Deficiencies in Interconnection Request), Tri-State argues that requiring interconnection customers to provide any requested information within

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[564] CAISO Initial Comments at 9.

[565] *Id.* (citing CAISO, CAISO Tariff, app. DD, §§ 3.5.1, 3.5.2.2 (16.0.0); *id.* § 6.1.2 (21.0.0)).

[566] Tri-State states that during its 2022 definitive interconnection system impact study request window, 75% of the interconnection requests were received during the last two days of the request window, and 50% of the interconnection requests were received in the last two days of the 2021 definitive interconnection system impact study request window. *Id.* at 10.

10 business days after receiving notice of deficiencies in the interconnection request, but no later than the close of the cluster request window, does not take into account that most requests are not submitted until the last day of the cluster request window.[567]

216. Regarding the number of cluster request windows opened each year, a couple of commenters argue that there should be more than one cluster request window per year.[568] Clean Energy States assert that, because presumably there will be fewer generator interconnection studies to be done, transmission providers should provide opportunities more frequently (e.g., quarterly) for interconnection customers to submit interconnection requests.[569] Environmental Defense Fund argues that the Commission should require that the cluster request windows occur bi-annually, rather than once a year, to reduce the delay caused by missing a cluster request window while still covering a large enough time period that a number of interconnection requests will be included in each cluster.[570]

217. Southern generally agrees with the Commission that a cluster study process, including the individual facilities study, should be completed within a year, but recommends eliminating unnecessary delays, such as multiple, overlapping clusters, by only permitting one cluster study at a time (i.e., that a new cluster should not commence

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[567] Tri-State Initial Comments at 27.

[568] Clean Energy States Initial Comments at 9; Environmental Defense Fund Initial Comments at 4.

[569] Clean Energy States Initial Comments at 9.

[570] Environmental Defense Fund Initial Comments at 4.

until the previous cluster has been completed).[571] According to Southern, under this format, an annual cluster study can be performed because the previous cluster study process has been completed. Southern asserts that overlapping cluster study processes will not help end interconnection queue backlogs and uncertainty, but rather add to them.

218. Regarding the length of the customer engagement window, Clean Energy Associations support the proposed 30-calendar day time frame for the customer engagement window as a baseline.[572] A number of commenters argue that the proposed 30-calendar day customer engagement window is too short and recommend a longer window.[573] Duke Southeast Utilities argue that, based on experience with Duke Carolinas Utilities' cluster study process, which includes a 60-calendar day customer engagement window, the proposed 30-calendar day customer engagement window may not provide sufficient time to facilitate robust engagement.[574] Duke Southeast Utilities therefore urge the Commission to adopt a 60-calendar day customer engagement window. Xcel describes PSCo's recent interconnection queue reform, which extended the

[571] Southern Initial Comments at 23-24.

[572] Clean Energy Associations Initial Comments at 19.

[573] APS Initial Comments at 10-11; CAISO Initial Comments at 8, 10-11; Duke Southeast Utilities Initial Comments at 8; ISO-NE Initial Comments at 23; Tri-State Initial Comments at 9-10; PJM Initial Comments at 20.

[574] Duke Southeast Utilities Initial Comments at 8.

customer engagement window to 95 calendar days to allow interconnection customers additional time to reevaluate their readiness in a way that includes other customers.[575]

219. ISO-NE suggests a 90-calendar day customer engagement window.[576] In addition, ISO-NE suggests that the Commission clarify that transmission providers may withdraw interconnection requests for which the models and data do not meet the requirements following the customer engagement window in order to improve efficiency. ISO-NE further asks that the Commission recognize the role of the participating transmission owners in performance of interconnection studies and build time into the cluster study time frames that accounts for this coordination.

220. Indicated PJM TOs argue that there should be a 30-calendar day window after the date that the cluster request window closes, and between the time the transmission provider posts the interconnection cases for the cluster study and the cluster study commences, during which interconnection customers qualified to receive CEII information have the opportunity to conduct their own studies with the transmission provider's base case and the new interconnection service requests. Indicated PJM TOs assert that during this time, interconnection customers should be able to withdraw their interconnection request with minimal financial impact.[577]

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[575] Xcel Initial Comments at 21 (citing *Pub. Serv. Co. of Colo.*, Docket No. ER22-2087-000 (Aug. 9, 2022) (delegated order)).

[576] ISO-NE Initial Comments at 23.

[577] Indicated PJM TOs Reply Comments at 6-7.

221. APS states that multiple customers requesting individual scoping meetings could place a significant burden on the transmission provider to schedule several meetings under a condensed time frame if the customer engagement window remains 30 calendar days.[578] For example, APS states that, assuming all notifications of valid interconnection requests are made by the time the customer engagement window starts, the interconnection customer has 15 business days to request an individual meeting and, if an interconnection customer uses all 15 business days, that is a minimum 21 calendar days out of the total 30 calendar days of the overall customer engagement window. APS contends that this leaves nine calendar days at most (i.e., no more than seven business days) to schedule an individual customer meeting, which could be less if there are holidays occurring within the customer engagement window.

222. Similarly, Tri-State argues that the proposed 30-day customer engagement window is not sufficient to meet the purpose of the customer engagement window and recommends it be extended to allow adequate time to cure deficiencies and hold individual scoping meetings.[579] Tri-State argues that a 75-day customer engagement window would give interconnection customers an opportunity to: (1) assess the viability of their proposed generating facilities before committing to the interconnection process

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[578] APS Initial Comments at 10.

[579] Tri-State Initial Comments at 9, 10.

and subjecting themselves to a withdrawal penalty; and (2) cure deficiencies in their interconnection requests.[580]

iii. Commission Determination

223. We adopt the proposed new *pro forma* LGIP section 3.4.1 (Cluster Request Window), which provides that interconnection customers must submit an interconnection request during a specified period—the cluster request window—a 45-calendar day period with the start date to be determined by each transmission provider. We also adopt the non-refundable $5,000 application fee required to be submitted with the interconnection request.[581] We also adopt the requirement that interconnection customers provide requested information within 10 business days of receiving an interconnection request deficiency notice but no later than the close of the cluster request window, as proposed and adopted in new *pro forma* LGIP section 3.4.4 (Deficiencies in Interconnection Request), but we modify that section to clarify the timeline for curing deficiencies. We modify the proposed new *pro forma* LGIP section 3.4.5 (Customer Engagement Window) and extend the customer engagement window from 30 days to 60 calendar days.

224. To ensure clarity for both interconnection customers and transmission providers, based on the record, we believe that 45 calendar days is a sufficient window to

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[580] *Id.* at 9.

[581] We note that the application fee is separate from the initial study deposit, commercial readiness deposit, and deposit in lieu of site control.

adequately notify prospective interconnection customers of the formation of a new cluster but not so long as to delay the processing of the interconnection queue.

225. Contrary to commenters' assertions, we are not persuaded to extend the cluster request window. We do not believe that more time is needed for transmission providers to work with interconnection customers that submitted invalid interconnection requests to cure deficiencies, particularly given the limit we adopt on the time for such additional information to be submitted by interconnection customers, and because the start date of the cluster request window will be included in the transmission provider's LGIP for prospective interconnection customers. We similarly do not believe that shortening the cluster request window would result in fewer "low quality" interconnection requests, as CAISO argues. Given the package of reforms adopted in this final rule, we expect fewer speculative interconnection requests and that interconnection customers will be more likely as a result of this final rule to submit interconnection requests for proposed generating facilities that they believe are viable and ready to move forward in the interconnection process.

226. As for Tri-State's concern about the requirement for correcting deficiencies in new *pro forma* LGIP section 3.4.4 (Deficiencies in Interconnection Request),[582] we clarify that the 10-business day window is the maximum time allowed to submit a response. This means that an interconnection customer that submits its interconnection request more than 10 business days before the close of the cluster request window will have a full

[582] Tri-State Initial Comments at 27.

10 business days to submit a response, whereas an interconnection customer that does not submit its interconnection request until less than 10 business days before the close of the cluster request window will have however many days remain in the cluster request window to respond to any deficiencies. Accordingly, we modify *pro forma* LGIP section 3.4.4 to provide that if the interconnection customer does not respond before the deadline: (1) the interconnection request is immediately deemed withdrawn (without the cure period provided under *pro forma* LGIP section 3.7); (2) the application fee is forfeited to the transmission provider; and (3) because the cluster study has not commenced, the study deposit and commercial readiness deposit are returned to the interconnection customer.

227. We decline to adopt revisions to the *pro forma* LGIP to require biannual or quarterly cluster study windows, as suggested by Clean Energy States and Environmental Defense Fund. Based on the record, we are not convinced that mandating multiple cluster request windows per year will result in a more efficient cluster study process, especially considering the various sizes of transmission provider footprints and interconnection queues. As we adopt an annual cluster study process, an annual cluster request window will allow transmission providers to dedicate resources to the cluster request window only once per year, dedicating their resources to the remainder of the cluster study process for the rest of the year. We also are not convinced by Environmental Defense Fund's concern with interconnection customers missing a cluster request window, as the date of the start of the cluster request window will be in each transmission provider's LGIP, providing sufficient notice for prospective interconnection

customers to prepare required application materials accordingly. We do not believe that additional rules are needed to govern how transmission providers will inform interconnection customers about the cluster request window.

228. We disagree with Southern's suggestion that the cluster study process should only permit transmission providers to conduct one cluster study at a time (i.e., eliminating the possibility of conducting multiple cluster studies at any time). Prohibiting the transmission provider from conducting overlapping cluster studies, in the instance where it is necessary to process cluster subgroups or to process delayed studies, would delay the interconnection process for interconnection customers. We therefore find that this suggestion would contribute to more backlogs and uncertainty, as delays to any cluster study would significantly delay cluster studies for all remaining interconnection requests in an interconnection queue and would be insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. Transmission providers with the capacity to conduct multiple cluster studies at a given time should be permitted to do so to facilitate more effective and efficient interconnection processes.

229. In response to MISO's concern about posting requirements close to the conclusion of the cluster request window, we reiterate that we are extending the length of the customer engagement window from the proposed 30 calendar days to 60 calendar days, which will allow transmission providers a total of 60 calendar days from the close of the cluster request window to post the list of interconnection requests for that cluster.

230. MISO argues that the Commission should not require any OASIS posting prior to the interconnection customer's finalization of the interconnection request because a definitive point of interconnection would have not yet been selected.[583] While we recognize MISO's concern about transmission providers posting interconnection request information on OASIS that may later change, we find that providing as much information as possible to interconnection customers early in the customer engagement window provides important transparency to improve interconnection queue processing. Providing information about other interconnection requests that may be studied within the same cluster to interconnection customers considering whether to execute a cluster study agreement and to continue with the cluster, may help them determine the viability of their proposed generating facilities, making it less likely that interconnection customers will withdraw later in the cluster study process, triggering delays and restudies and the associated problems discussed in Section II of this final rule.

231. We disagree with Clean Energy States' assertion that a cluster should be able to be modified in response to interconnection customer changes or study findings without threatening the interconnection customer's relative queue priority or paying penalties.[584] Any interconnection customer that submits a valid interconnection request during the customer request window will become part of the cluster, if the interconnection customer chooses to execute a cluster study agreement by the end of the customer engagement

[583] MISO Initial Comments at 36-37.

[584] Clean Energy States Initial Comments at 9.

window. The transmission provider may not modify the makeup of the cluster or pick and choose which interconnection customers to keep in the cluster in the way Clean Energy States describes. We also note that interconnection customers can request a modification assessment pursuant to section 4.4 of the *pro forma* LGIP.

232. Regarding the customer engagement window, we adopt the NOPR proposal to add a new section 3.4.5 (Customer Engagement Window) to the *pro forma* LGIP, which provides that, following the close of the cluster request window, the transmission provider begins a customer engagement window. Additionally, we modify the proposal to extend the customer engagement window from 30 calendar days, as proposed, to 60 calendar days. Under this provision, the transmission provider must post new cluster information on OASIS with details of each interconnection request for that cluster, including information on the amount of interconnection service and the location of the proposed generating facility, within the first 10 business days of the customer engagement window. While we extend the customer engagement window from 30 calendar to 60 calendar days, we retain the proposed 10 business day deadline by which the transmission provider must post new cluster information on OASIS. We find that it is more beneficial for interconnection customers to have this information as early as possible, such that they are able to assess the composition of the cluster and make informed choices moving forward with their interconnection requests earlier rather than later in the customer engagement window. Further, during the customer engagement window, an interconnection customer may withdraw its interconnection request without penalty.

233. We extend the customer engagement window to 60 calendar days in response to numerous commenters' arguments that 30 calendar days is insufficient to adequately engage with interconnection customers in a cluster, including based on experience implementing a similar cluster study process to that we require as part of this final rule.[585] By extending the customer engagement window, we provide transmission providers with additional time to conduct individual meetings with interconnection customers that submitted interconnection requests within the cluster request window, lessening the burden on transmission providers, particularly larger transmission providers such as RTOs/ISOs.[586] At the same time, we provide interconnection customers with more time to consider information collected during this period of engagement with the transmission provider—including the makeup of the cluster—and assess the continued viability of their proposed generating facilities before withdrawal of the interconnection request will incur a penalty. For example, the interconnection customer can assess the expected costs of potential network upgrades and the impact of those costs on the viability of its proposed generating facility in the context of the size and location of other interconnection requests in the cluster. Interconnection customers will have 46 calendar days to consider the posted information (which must be posted within 10 business days after the start of the customer engagement window). Not only will this longer time

[585] Duke Southeast Utilities Initial Comments at 8; PJM Initial Comments at 20; Xcel Initial Comments at 21 (citing *Pub. Serv. Co. of Colo.*, Docket No. ER22-2087-000 (Aug. 9, 2022) (delegated order)).

[586] PJM Initial Comments at 20; ISO-NE Initial Comments at 23.

period for interconnection customers to consider whether to withdraw their interconnection requests prior to the start of the cluster study save interconnection customers' resources by avoiding future penalties, but it will also result in more efficient interconnection queue processing with fewer withdrawals later in the cluster study process—withdrawals that can trigger restudies and cause the problems discussed in Section II of this final rule.

234. We reject Southern's suggestion that if an interconnection request is not deemed valid,[587] the interconnection request should be withdrawn from the interconnection queue. Under new section 3.4.5 of the *pro forma* LGIP, any interconnection requests not deemed valid at the close of the customer engagement window will not be included in the cluster. This provision is designed to ensure that interconnection customers and transmission providers have sufficient time to conduct scoping meetings and to discuss and comprehensively evaluate whether interconnection requests are fully valid during the customer engagement window. We find that forced withdrawals prior to the close of the customer engagement window could result in potentially valid interconnection requests being rejected prior to allowing for interconnection customers and transmission providers to discuss alternative interconnection options, exchange information that could impact such options, and conduct due diligence informed by information discussed during the customer engagement window per the provisions set forth in new *pro forma* LGIP section 3.4.6 detailing scoping meetings.

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[587] Southern Initial Comments at 37.

235. In response to EPSA,[588] we note that transmission providers and interconnection customers should always work in a manner that is fair and nondiscriminatory, including during the customer engagement window and study agreement negotiation.

236. We decline to adopt MISO's suggestion that transmission providers allow interconnection customers to submit an interconnection request prior to the beginning of the cluster request window. We note that the cluster request window is specifically designed to structure when transmission providers should expect interconnection customers to submit interconnection requests for assessment. We find that allowing interconnection request submission prior to the cluster request window may be burdensome to transmission providers, who would have to dedicate staff and resources towards assessing the viability of interconnection requests before the designated request window opening, instead of concentrating their resources towards the prior stage of the interconnection process.

237. We agree with Enel's recommendation that the Commission include language in the *pro forma* LGIP that, in the cluster study process, the transmission provider will not post detailed information about interconnection requests proceeding or withdrawing until all interconnection requests successfully meet their milestone requirements to proceed, withdraw, or fail to cure their breach within the specific cure period. We note that transmission providers are required to post this information at the conclusion of the cluster request window, at which point interconnection customers must provide

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[588] EPSA Initial Comments at 7.

significant requirements to proceed. We find that maintaining confidentiality early in the customer engagement window stage is appropriate to reduce opportunities for developers to gain competitive advantage over others before interconnection requests have been finalized and accepted by the transmission provider. We therefore adopt the following modification to section 3.4.5 of the *pro forma* LGIP (addition in italics): "Within ten (10) Business Days after the close of the Cluster Request Window, Transmission Provider shall post on its OASIS site a list of Interconnection Requests for that Cluster. The list shall identify, for each *anonymized* Interconnection Request[s]: (1) the requested amount of Interconnection Service; (2) the location by county and state; (3) the station or transmission line or lines where the interconnection will be made; (4) the projected In-Service Date; (5) the type of Interconnection Service requested; and (6) the type of Generating Facility or Facilities to be constructed, including fuel types, such as wind, natural gas, coal, or solar. *The transmission provider must ensure that project information is anonymized and does not reveal the identity or commercial information of interconnection customers with submitted requests.*" Further, as discussed below, we modify section 3.4.6 of the *pro forma* LGIP to require that transmission providers exercise the use of non-disclosure agreements to maintain confidentiality of identifying or commercially sensitive information for all other interconnection customers in a group scoping meeting.

e. Scoping Meeting

i. NOPR Proposal

238. In the NOPR, the Commission proposed to renumber and revise section 3.4.4 of the *pro forma* LGIP as section 3.4.6 to provide that, during the proposed customer engagement window, transmission providers must hold a scoping meeting with all interconnection customers whose valid interconnection requests were received in that cluster request window.[589] Revised section 3.4.6 of the *pro forma* LGIP would also require transmission providers to hold individual customer-specific scoping meetings, at the interconnection customer's request, which must be requested by no later than 15 business days after the close of the cluster request window.

ii. Comments

239. MISO supports the Commission requiring individual customer-specific scoping meetings only when requested by interconnection customers.[590] APS agrees that a single scoping meeting with all interconnection customers in the cluster during the customer engagement window is beneficial to transmission providers and eases the burden of scheduling individual meetings with all parties. However, APS has concerns about security and confidentiality.[591] APS notes that, currently, each interconnection customer in the interconnection queue is provided a queue number that becomes the only

[589] NOPR, 179 FERC ¶ 61,194 at P 68.

[590] MISO Initial Comments at 35-36.

[591] APS Initial Comments at 10.

identifying information posted publicly. APS requests that the Commission provide clarity on whether the requirements to treat additional information as confidential no longer apply or if there is a form of good utility practice as it pertains to holding a single scoping meeting without revealing the identities of the other interconnection customers involved and some examples thereof.

240. MISO expresses concern that the timelines listed in the customer engagement window for posting information are impractical. MISO asserts that the Commission should not require a posting so near the close of the request window because the transmission provider must devote its resources to reviewing the interconnection requests for deficiencies.[592]

241. Enel and AEE argue that the Commission should also require transmission providers and transmission owners to hold individual, customer-specific scoping meetings at the request of the interconnection customer *before* the customer commits to entering the cluster.[593] Enel states that an individual pre-interconnection queue scoping meeting would be an opportunity for the interconnection customer to ask basic questions that can help inform economically significant decisions an interconnection customer faces in deciding to enter the interconnection queue.[594] As an alternative to requiring a pre-interconnection queue meeting, Enel suggests that the Commission could require

[592] MISO Initial Comments at 36.

[593] AEE Initial Comments at 10; Enel Initial Comments at 10.

[594] Enel Initial Comments at 10.

transmission providers to maintain an electronic inbox where prospective interconnection customers could submit interconnection-related questions and be guaranteed a response in time to inform decisions on entering the interconnection queue.

242. PJM believes that "grouping kick off meetings" will reduce the burden on transmission owners and providers of scheduling and participating in hundreds of meetings, and the burden on interconnection customers of waiting for their meeting to be scheduled.[595] PJM requests clarification that a transmission provider may group requests for this customer engagement window unless an interconnection customer requests otherwise.

243. Tri-State asks the Commission to consider providing only one week to schedule the requested individual customer-specific scoping meeting if the interconnection customer does not request a scoping meeting until the fifteenth business day.[596]

244. Noting the difficulty of coordinating in-person scoping meetings, SEIA requests that the Commission clarify that both generating facility-specific and cluster scoping meetings must provide the option for interconnection customers to attend via teleconference, which is currently not available in all regions.[597] Enel suggests that, for all scoping meetings, the Commission should require transmission owners, not just interconnection customers and transmission providers, to attend; otherwise, Enel

[595] PJM Initial Comments at 20-21.

[596] Tri-State Initial Comments at 27.

[597] SEIA Initial Comments at 8.

continues, there could be crucial questions that the transmission provider may not be able to answer.[598]

iii. Commission Determination

245. We adopt, in part, the proposed revisions to section 3.4.6 of the *pro forma* LGIP, and therefore require that, during the customer engagement window, transmission providers hold a scoping meeting with all interconnection customers whose interconnection requests were received in that cluster request window. We decline to adopt the NOPR proposal to require transmission providers to hold individual customer-specific scoping meetings at the interconnection customer's request.

246. These revisions to the *pro forma* LGIP align the timing and purpose of scoping meetings between transmission providers and interconnection customers with the adoption of the cluster study process in this final rule. We do not believe that providing the option for interconnection customers to request an individual customer-specific scoping meeting is necessary to ensure that interconnection customer-specific questions are answered as interconnection customers consider whether to remain in the interconnection queue for the cluster study or to withdraw their interconnection request. We find that this requirement would be comparatively inefficient and burdensome for transmission providers, leading to potentially significant interconnection delays. We thus find that this requirement would be inconsistent with the goal to ensure that interconnection customers are able to interconnect to the transmission system in a

[598] Enel Initial Comments at 11.

reliable, efficient, transparent, and timely manner. We find that the cluster-wide scoping meeting is an appropriate forum in which all interconnection customers can direct questions to transmission providers in an efficient manner without delaying the cluster process with unnecessarily time-consuming individual scoping meetings.

247. We agree with APS' concerns pertaining to good utility practices[599] for security and confidentiality regarding the disclosure of potentially sensitive commercial information during the cluster scoping meeting that will include numerous interconnection customers in the cluster.[600] We therefore modify section 3.4.6 of the *pro forma* LGIP to require that transmission providers use non-disclosure agreements to maintain confidentiality of identifying or commercially sensitive information for all other interconnection customers in a group scoping meeting until the close of the customer engagement window.

248. In response to Enel and AEE,[601] we will not modify the *pro forma* LGIP to require transmission providers to hold individual interconnection customer-specific scoping

[599] Good utility practice means "any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region." *See pro forma* LGIP section 1 (Definitions).

[600] APS Initial Comments at 10.

[601] AEE Initial Comments at 10; Enel Initial Comments at 10.

meetings at the request of the interconnection customer before the interconnection customer commits to entering the cluster. As discussed above, we decline to adopt a requirement that transmission providers conduct individual interconnection customer scoping meetings. Additionally, as discussed above,[602] we adopt the heatmap requirement, which will assist interconnection customers prior to entering the interconnection queue in evaluating the viability of their proposed generating facilities, and we are also permitting interconnection customers to withdraw from the interconnection queue without penalty prior to the close of the customer engagement window. With these reforms, we do not believe that pre-interconnection queue scoping meetings should be required to ensure just and reasonable rates.

249. In response to MISO's concern about posting requirements close to the conclusion of the cluster request window,[603] we find that allowing transmission providers a total of 10 business days from the close of the cluster request window to post the required list of interconnection requests for that cluster is a reasonable amount of time.

250. In response to SEIA,[604] we decline to modify the *pro forma* LGIP to require transmission providers to include an option for interconnection customers to attend via teleconference for cluster-wide scoping meetings. We do not believe that such level of

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[602] *See supra* Section III.A.1.c.

[603] MISO Initial Comments at 36.

[604] SEIA Initial Comments at 8.

logistical specification governing how transmission providers choose to conduct scoping meetings with interconnection customers is needed in the *pro forma* LGIP.

251. In response to Enel,[605] we decline to modify the *pro forma* LGIP to require transmission owners, not just interconnection customers and transmission providers, to attend scoping meetings. The *pro forma* LGIP contemplates that the transmission owner and transmission provider may be the same entity, except in the case of an RTO/ISO, in which case the transmission owner does not have operational control of the facilities and does not perform cluster studies. In the case of an RTO/ISO, only the entity that independently administers the cluster study is required to attend the scoping meeting.

f. <u>Posting of Metrics for Cluster Study Processing Time and Restudy Processing Time</u>

i. <u>NOPR Proposal</u>

252. In the NOPR, the Commission proposed to revise the requirements included in section 3.5.2 of the *pro forma* LGIP to post metrics for interconnection feasibility study processing time and system impact study processing time, to instead require transmission providers to post metrics for cluster study processing time and cluster restudy processing time.[606] The Commission also proposed to require transmission providers to post the time from when the transmission provider received a valid interconnection request to the completion of the cluster study, cluster restudy, and facilities study.

[605] Enel Initial Comments at 11.

[606] NOPR, 179 FERC ¶ 61,194 at P 69.

253. Specifically, in section 3.5.2.1 of the *pro forma* LGIP, the Commission proposed requiring that transmission providers must post the number of interconnection requests that had cluster studies completed within the transmission provider's coordinated region during the reporting quarter that were completed more than 150 calendar days after the close of the customer engagement window. Similarly, in section 3.5.2.2 of the *pro forma* LGIP, the Commission proposed requiring that transmission providers must post the number of interconnection requests that had cluster restudies completed within the transmission provider's coordinated region during the reporting quarter that were completed more than 150 calendar days after the transmission provider's receipt of the interconnection customer's executed cluster restudy agreement.

254. In section 6.4 of the *pro forma* LGIP, the Commission proposed that transmission providers publicly post new metrics requirements on their websites pertaining to various technical specifications for, and impacts of, potential generating facilities on the transmission provider's transmission system, requiring that these metrics must be updated on the transmission provider's website "within 30 days after the completion of each Cluster Study and Cluster Restudy period."[607]

ii. Comments

255. Clean Energy Associations support the proposal to require the posting of metrics for cluster study processing time and cluster restudy processing time, starting from when

[607] Proposed *pro forma* LGIP section 6.4.

the transmission provider received a valid interconnection request.[608] Clean Energy Associations further argue that these reports should also identify the level of accuracy of these studies relative to final costs.

256. While supportive of the use of metrics that reflect cluster study and cluster restudy processing time, some commenters do not support measuring these metrics from the date that the transmission provider received the interconnection request.[609] APS argues that this seems contradictory to the NOPR proposal that the 150-day timeline to process cluster study requests begins at the end of the customer engagement window.[610] MISO asserts that for study metrics to be a useful measurement of whether a transmission provider is meeting its tariff deadlines, the start date used in the metrics must reflect when studies actually commence.[611] MISO notes that an interconnection customer may choose to submit its interconnection request weeks ahead of the cluster request window deadline and that the time between that deadline and study commencement is variable.[612] MISO urges the Commission to allow RTOs/ISOs flexibility to maintain metrics that reflect their tariff deadlines, especially where the RTO/ISO already has a Commission-approved cluster study process.

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[608] Clean Energy Associations Initial Comments at 20-21.

[609] APS Initial Comments at 9; MISO Initial Comments at 37.

[610] APS Initial Comments at 9.

[611] MISO Initial Comments at 38.

[612] *Id.* (submitting MISO's tariff as an example).

257. Ameren contends that if the Commission retains the proposal to require the posting of the time from when the transmission provider received a valid interconnection request to the completion of the cluster study, cluster restudy, and facilities study, it should clarify that in the context of an RTO/ISO, "complete" refers to the final sign-off by the RTO/ISO.[613] Ameren asserts that transmission owners within an RTO/ISO may act on behalf of the RTO/ISO transmission provider for purposes of certain studies; however, it is the RTO/ISO and not the transmission owner that decides when a study is complete.

258. In section 6.4 of the *pro forma* LGIP, regarding the proposed requirement that "[t]hese metrics must be updated within 30 days after the completion of each Cluster Study and Cluster Re-study period[,]" Enel recommends that the word "period" should be deleted. Enel argues that the trigger should be the completion of the studies themselves.[614]

iii. <u>Commission Determination</u>

259. We adopt the proposed revisions to section 3.5.2 of the *pro forma* LGIP to require transmission providers to post metrics for cluster study processing time and cluster restudy processing time, including the number of cluster studies completed within 150 calendar days of the close of the customer engagement window. We modify section 3.5.2.2 of the *pro forma* LGIP as proposed in the NOPR to be consistent with the

[613] Ameren Initial Comments at 10-11.

[614] Enel Initial Comments at 83.

new requirement adopted in section 7.5 of the *pro forma* LGIP that cluster restudies should be completed within 150 calendar days of the transmission provider notifying interconnection customers in the cluster and that a cluster restudy is required. The requirement to post these metrics replaces the existing requirement to post metrics for interconnection feasibility study processing time and system impact study processing time, which were relevant for the serial study process but are no longer relevant for the cluster study process required by this final rule. We therefore believe that these revisions are necessary to implement the change from a serial study process to the cluster study process.

260. As for the point at which to begin measuring the metrics, several commenters argue against using the date on which the transmission provider received the interconnection requests. We clarify that sections 3.5.2.1 and 3.5.2.2 of the *pro forma* LGIP adopted in this final rule establish that these metrics must be measured from the close of the customer engagement window for the cluster study processing time metric and from when transmission provider notifies interconnection customers in the cluster that a cluster restudy is needed for the cluster restudy processing time metric. We find that these are appropriate start dates from which to calculate the metrics because they reflect when the respective studies are to actually commence.[615] We decline to grant

[615] APS Initial Comments at 9; MISO Initial Comments at 37-38.

additional flexibility to maintain metrics and associated timelines for those metrics, as urged by MISO.[616]

261. Regarding Clean Energy Associations' suggestion that the metrics also identify the level of accuracy of studies relative to final costs,[617] we decline to adopt this suggestion. For one, it is unclear to what final costs Clean Energy Associations is referring to. Additionally, the metrics that we require transmission providers to post as part of this final rule focus on the timing of interconnection studies and not on the accuracy of cost estimates. The metrics are intended, as described in Order No. 845, to provide needed transparency "to allow interconnection customers to develop informed expectations about how long the interconnection study portion of the process actually takes."[618]

262. We decline to adopt Ameren's suggestion to base the 150-calendar day cluster study deadline on the RTO/ISO's completion of the cluster study rather than the transmission owner's completion because the deadlines are applicable to the transmission provider and such a clarification is unnecessary to be added to the *pro forma* LGIP.

263. We agree with Enel's suggestion to modify proposed *pro forma* LGIP section 6.4 – now *pro forma* LGIP section 6.1 – by deleting "period" because, as Enel explains, this

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[616] MISO Initial Comments at 38.

[617] Clean Energy Associations Initial Comments at 21.

[618] Order No. 845, 163 FERC ¶ 61,043 at P 307.

would more concisely convey that the metrics should be updated following the completion of the studies themselves.[619]

g. Interconnection Request Evaluation Process

i. NOPR Proposal

264. In the NOPR, the Commission proposed several changes to *pro forma* LGIP section 4, renamed "interconnection request evaluation process" from "queue position." First, the Commission proposed to rename and revise section 4.1 of the *pro forma* LGIP as "queue position" and added two new proposed sections: (1) section 4.1.1 (Assignment of Queue Position), which provides that queue position will be based on the time and date that the transmission provider receives all items required under section 3.4 (Valid Interconnection Request) and that there is no queue priority for interconnection customers that opted for informational interconnection studies; and (2) section 4.1.2 (Higher Queue Position), which provides that all interconnection requests studied in a single cluster shall be considered to have equal queue priority, but clusters initiated earlier in time shall be considered to have a higher queue position than clusters initiated later in time.[620]

265. The Commission also proposed to remove from section 4.2 of the *pro forma* LGIP the provisions allowing transmission providers to study interconnection requests serially and the requirement for transmission providers to provide 180 calendar days' advance

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[619] Enel Initial Comments at 83.

[620] NOPR, 179 FERC ¶ 61,194 at P 70.

notice before opening a cluster window.[621] The Commission also proposed to rename section 4.2 of the *pro forma* LGIP "general study process," and revise it to require transmission providers to perform interconnection studies within the cluster study process.

266. In the NOPR, the Commission also proposed changes to the material modification provisions in section 4.4 (Modification) of the *pro forma* LGIP to provide that moving a point of interconnection shall result in a loss of interconnection queue position if it is deemed a material modification by the transmission provider. Additionally, proposed additions to *pro forma* LGIP section 4.4 require that any identified changes to a planned interconnection, proposed by an interconnection customer or the transmission provider, must be acceptable to any impacted interconnection customer in the same cluster, and such acceptance is not to be unreasonably withheld.[622] The Commission noted that the interconnection customer may decide to forego the requested change that constitutes a material modification and retain its existing queue position.[623]

267. Further, the Commission proposed to revise section 4.4.1 of the *pro forma* LGIP to make clear that: (1) the modifications previously permitted prior to return of the executed system impact study agreement are now permitted to be made prior to return of the executed cluster study agreement; and (2) for generating plant increases, the

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[621] *Id.* P 72.

[622] Proposed *pro forma* LGIP section 4.4.

[623] NOPR, 179 FERC ¶ 61,194 at P 71.

incremental increase will be studied with the next cluster study for purposes of cost allocation and study analysis.[624] *Pro forma* LGIP section 4.4.1 also explicitly permits specific modifications prior to the interconnection customer's return of the executed cluster study agreement to the transmission provider, including: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project, through either a decrease in plant size or a decrease in interconnection service level; (b) modifying the technical parameters associated with the generating facility technology or step up transformer; and (c) modifying the interconnection configuration.

ii. Comments

268. With regards to the proposed changes to section 4.1 (Queue Position), Tri-State questions whether the proposed definition of queue position includes surplus interconnection requests.[625] Xcel argues, and EEI agrees, that the Commission should modify the proposal to clarify that queue position or queue priority is based on interconnection request readiness and not on the date and time the interconnection request is submitted.[626]

269. CAISO asserts that it is unclear what losing a queue position means in a cluster-based study (e.g., being withdrawn from the interconnection queue or moving to a lower interconnection queue position), but also contends that no specification or reform is

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[624] *Id.* P 73.

[625] Tri-State Initial Comments at 25.

[626] EEI Reply Comments at 5; Xcel Initial Comments at 9 n.12.

necessary because interconnection customers will simply withdraw the modification every time if it is found to be material.[627] CAISO argues that the Commission should either remove the "option" to lose an interconnection queue position when a proposed modification is found to be material, or clarify what replaces the interconnection queue position when it is lost.

270. Clean Energy States argue that, in addition to the "signs of commercial progress" proposed by the Commission, clusters should be prioritized for study based on a number of other transparent and quantifiable factors, such as alignment with state policy (e.g., participation in procurement actions), and benefits to low-income, environmentally impacted, and "energy communities" as defined under the Inflation Reduction Act, state policies, and the Justice40 Initiative.[628] Clean Energy States assert that clusters could further be prioritized for development by how well the combined cluster meets transmission system needs, with preference for interconnection agreements given to those that result in the lowest cost upgrades, have the most attractive operational profile, or deliver the best reliability improvements.

271. Regarding the proposed changes to *pro forma* LGIP section 4.4 (Modifications), Enel argues that the Commission should remove the proposed language requiring the acceptance of "any impacted Interconnection Customer in the same Cluster" to modify an

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[627] CAISO Initial Comments at 11-12.

[628] Clean Energy States Initial Comments at 8.

interconnection request.[629] Enel asserts that this requirement not only will be challenging to facilitate (especially in large clusters) but is also a redundant and unnecessary hurdle that could result in anticompetitive behavior. If the Commission keeps this language, to avoid uncertainty regarding the application of this provision, Enel proposes to replace this language with "any Interconnection Customer in the same Cluster whose interconnection would be delayed or whose interconnection-related costs would be increased as a result of the identified changes."[630]

272. A few commenters argue that the Commission should consider changes to the material modification process such that only certain modifications trigger a restudy.[631] Clean Energy Associations recommend that the Commission modify the current material modification definition to clearly state that certain changes are presumptively immaterial, such as changing solar modules or turbines, adding storage capacity, or making minor adjustments to inverter performance. Clean Energy Associations argue that this presumption should be in place so long as planned export and import capacity remains the same.[632] Clean Energy Associations also support the concept of expedited, limited studies for project modifications, provided that: (1) an expedited approach does not

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[629] Enel Initial Comments at 19-20.

[630] *Id.* at 83.

[631] AEP Initial Comments at 18; Clean Energy Associations Initial Comments at 42; Pattern Energy Initial Comments at 17; PPL Initial Comments at 11.

[632] Clean Energy Associations Initial Comments at 42.

change the level of interconnection service; (2) there is no impact on cost or timing of an interconnection request that is lower- or equally queued; and (3) it does not cause any reliability concern. Additionally, Pattern Energy asserts that, in its experience, transmission providers apply widely disparate standards where even de minimis impacts—timing or financial—can be determined to be material, which Pattern Energy believes is unreasonable and unduly discriminatory in light of the dynamic nature of the generator interconnection processes.[633] Pattern Energy argues that, absent severe delay, timing delay should not be factored into materiality. Pattern Energy suggests instead that materiality be tied to financial impact on a proposed generating facility (or group of proposed generating facilities).

273. With regard to modifications under proposed *pro forma* LGIP section 4.4.1, MISO supports the proposed revisions to avoid proposed project service level increasing[634] and other changes disrupting cluster studies that are in progress or delaying the negotiation and execution timelines for the LGIA.[635]

274. Enel recommends that the Commission modify the proposed *pro forma* LGIP section 4.4.1 language to give interconnection customers flexibility in the initial stages of interconnection studies, otherwise, it argues that, interconnection customers are more

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[633] Pattern Energy Initial Comments at 16-17.

[634] We understand MISO to be referring to the NOPR proposal that clarified that for plant increases, the incremental increase will be studied with the next cluster study for purposes of cost allocation and study analysis.

[635] MISO Initial Comments at 39.

likely to work around the rules by submitting multiple smaller interconnection requests to retain size flexibility after seeing their initial results, which is more administratively burdensome for transmission providers and leads to its own form of inefficiency as size reductions come in the form of withdrawals at any point in the process rather than being limited to partial reductions prior to entering the cluster restudy.[636]

275. CREA and NewSun argue that the Commission should explicitly permit interconnection customers to modify their interconnection requests to reduce or eliminate the assignment of network upgrade or stand alone network upgrade costs associated with a proposed generating facility after receipt of the first cluster-level interconnection study.[637] CREA and NewSun argue that interconnection customers should be permitted to modify their proposed generating facilities to avoid impacts on the transmission system that trigger network upgrades by, for example, reducing their capacity or installing devices that will limit their output during critical periods.[638] CREA and NewSun state that the existing *pro forma* LGIP allows an interconnection customer to downsize its interconnection capacity up to 60% upon receipt of the first interconnection study (i.e., the feasibility study) and before progressing to the second study (i.e., the system impact

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[636] Enel Initial Comments at 16-17 (proposing the section be revised to read: "Prior to the deadline to return the milestones listed in Section 7.5 of this LGIP to proceed into the initial Cluster Re-study, modifications permitted . . . .").

[637] CREA and NewSun Initial Comments at 45-47.

[638] *Id.* at 46.

study).[639] CREA and NewSun state that, in contrast, the NOPR proposes to only allow downsizing to occur before receipt of the first cluster system impact study and, as a result, the opportunity to downsize the interconnection request to tailor the facility to the available capacity identified in the first useful interconnection study would be lost. Therefore, CREA and NewSun argue that the Commission should revise the NOPR proposal to ensure that a reasonable amount of downsizing (e.g., 60%) is permitted after receipt of the first cluster-level interconnection study.[640]

iii. <u>Commission Determination</u>

276. We adopt the proposed revisions to *pro forma* LGIP section 4.1 (Queue Position), section 4.2 (General Study Process), and section 4.4.1, and we modify the proposed definition of queue position and the proposed revisions to the material modification provisions in section 4.4 (Modification). These are discussed below.

277. First, we adopt the proposed revisions to section 4.1 of the *pro forma* LGIP (Queue Position), which reflect the impact of the adoption of the proposed cluster study process in this final rule on queue position assignments. These revisions provide that transmission providers must assign queue positions based on the date and time of receipt of a valid interconnection request, but all interconnection customers that submit interconnection requests within a cluster request window must be considered equally

[639] *Id.* (citing NOPR, 179 FERC ¶ 61,194 at app. B (proposed *pro forma* LGIP section 4.4.1)).

[640] *Id.* at 47.

queued. Clusters initiated earlier in time must have a higher queue position than clusters initiated later in time. Under the existing serial study process in the *pro forma* LGIP, queue position had a greater effect on an interconnection customer, for instance, in the allocation of network upgrade costs. By contrast, network upgrade costs within a cluster will not be allocated by queue position; rather, as discussed below, network upgrade costs within a cluster must be allocated generally through a proportional impact method among the interconnection customers in the cluster. Given the nature of the cluster study process, including the nature of the cost allocation for network upgrades, it is appropriate for all interconnection customers in a cluster to be considered equally queued.

278. Second, we adopt the proposal to remove from section 4.2 of the *pro forma* LGIP the provisions allowing transmission providers to study interconnection requests serially and the requirement for transmission providers to provide 180 days' advance notice before opening a cluster window. We also adopt the proposal to rename section 4.2 of the *pro forma* LGIP "General Study Process" and revise it to require transmission providers to perform interconnection studies within the cluster study process. These revisions are necessary to implement the cluster study process required by this final rule.

279. As requested by Tri-State, we clarify that the definition of queue position is not relevant to surplus interconnection requests, which are processed outside of the normal interconnection queue, as further discussed in Section III.A.2.n below.

280. We also maintain the language in the *pro forma* LGIP that moving a point of interconnection in a way that is deemed a material modification will impact an interconnection customer's queue position, but we clarify the meaning of this in the

context of the cluster study process. Specifically, if moving a point of interconnection is deemed by the transmission provider to be a material modification to the interconnection request, and the interconnection customer chooses to proceed with the proposed modification, the interconnection request will be deemed withdrawn and the interconnection customer must re-enter the interconnection queue with a new interconnection request, if it desires to proceed to interconnect. To avoid being deemed withdrawn, the interconnection customer may choose not to move its point of interconnection and to instead remain in the same cluster with the original interconnection request, and, thus, in the same queue position.

281. In response to CREA and NewSun, we do not opine on whether moving a point of interconnection within a cluster will be a material modification. Instead, we leave the determination as to whether it is deemed a material modification to the transmission provider, as in the existing process for determining whether a proposed modification is material.

282. We decline to adopt Clean Energy States' suggestion that, in addition to the "signs of commercial progress" proposed by the Commission, clusters should be prioritized for study based on other transparent and quantifiable factors.[641] Clean Energy States neither provides sufficient rationale or detail regarding such factors by which clusters would be prioritized by transmission providers, nor explains how such prioritization criteria would be determined. We note that the Commission did not propose alternative factors for

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[641] Clean Energy States Initial Comments at 8.

consideration. Additionally, we note that the record lacks adequate discussion in favor of such prioritization mechanisms or such "factors" for the Commission to consider adopting in this final rule.

283. Third, we modify the proposed definition of queue position in the *pro forma* LGIP and LGIA to provide that queue position is established pursuant to section 4.1 of the *pro forma* LGIP. Fourth, we modify the proposed revisions to the material modification provisions in section 4.4 (Modification) of the *pro forma* LGIP. We adopt the language that provides that moving a point of interconnection shall result in a loss of queue position if it is deemed a material modification by the transmission provider, for the reasons discussed above. At the same time, we modify the proposed revisions to remove the requirement to obtain the approval of "any impacted Interconnection Customer in the same Cluster."[642] We are persuaded by Enel's argument that this proposed language in *pro forma* LGIP section 4.4 should be struck for two reasons. First, we find this language unnecessary because the point of interconnection could be changed only if the transmission provider had deemed it to not be a material modification to the interconnection request. Through this requirement, the transmission provider's analysis ensures that the change will not have a material impact on the cost or timing of another interconnection request in the cluster. Second, although the proposal included the language "such acceptance not to be unreasonably withheld," we are still concerned about the potential for anticompetitive behavior to the extent that other interconnection

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[642] Proposed *pro forma* LGIP section 4.4.

customers in the cluster could refuse to accept the point of interconnection change to limit competition. The interconnection customers within a cluster will be competitors in the wholesale markets in many, if not all, respects. To ensure competitive market outcomes, they should not be provided an undue opportunity to affect the advancement or the costs for a proposed generating facility of one of their competitors.

284. A number of commenters argue that the Commission should consider changes to the material modification process such that only certain modifications trigger a restudy.[643] We decline to adopt any of the suggested revisions to the material modification provisions and restudy triggers in the *pro forma* LGIP. We did not propose changes suggested by commenters and do not find the need to adopt such changes to the material modification provisions to ensure just and reasonable rates. We believe that the list of permitted modifications in section 4.4 of the *pro forma* LGIP is appropriate because they allow interconnection customers a degree of flexibility with respect to generating facility size, interconnection service level, and specific generating facility technology that appropriately balances the high burden to enter the interconnection queue and the lengthy duration of the interconnection queue, during which external factors may change, including the introduction of new technology that interconnection customers may wish to incorporate into their generating facility design.

[643] AEP Initial Comments at 18; Clean Energy Associations Initial Comments at 42; Pattern Energy Initial Comments at 17; PPL Initial Comments at 11.

285. Finally, we adopt the proposed revisions to section 4.4.1 of the *pro forma* LGIP to make clear that: (1) the modifications previously permitted prior to the return of the executed system impact study agreement are now permitted to be made prior to return of the executed cluster study agreement; and (2) for plant increases, the incremental increase will be studied with the next cluster study for purposes of cost allocation and study analysis. We believe that these revisions are needed to implement the cluster study process adopted to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. Notably, we believe that prior to the return of the executed cluster study agreement is the appropriate time to permit the modifications previously permitted prior to the return of the executed system impact study agreement because these represent approximately the same point of the interconnection process in a serial study process versus a cluster study process. For plant increases, we find that it is appropriate to exclude increases to proposed generating facility size from the cluster study that is ongoing as any increase to size may create the need for restudies. By moving the increase to the subsequent cluster, the interconnection customer can still pursue its requested addition, albeit on a delayed schedule.

286. We decline to adopt Enel's alternative proposed language that would allow the same modifications permitted to be made prior to the executed cluster study agreement to also be permitted before a cluster restudy. This would not only represent a significant change from the existing modification language in *pro forma* LGIP section 4.4.1, but allowing such modifications at the cluster restudy stage could negatively affect the integrity of the cluster and cause further restudies, which would not ensure that

interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

287. We also decline to adopt the revisions suggested by CREA and NewSun that would explicitly permit interconnection customers to modify their interconnection requests to reduce or eliminate the assignment of network upgrade or stand alone network upgrade costs associated with a proposed generating facility after receipt of the first cluster-level interconnection study. The "loss" of the opportunity for interconnection customers to downsize the interconnection request to tailor the facility to the available capacity identified in the first useful interconnection study[644] reflects the nature of moving from a serial study process, with an initial, high-level feasibility study, to a cluster study process, with the benefit of a customer engagement window, potential for shared cost allocation, and lower likelihood of cascading restudies. Moreover, providing interconnection customers an opportunity to reduce the size of their proposed generating facilities after the cluster study would undercut the increased certainty and efficiency that are key benefits of the shift to a cluster study process. With the adoption of clusters, a reduction in size that may eliminate one interconnection customer's cost responsibility for a network upgrade could affect other interconnection customers in the cluster, either by increasing their costs or requiring a different network upgrade. This type of uncertainty could lead to further reductions, withdrawals, and restudies, and would be insufficient to ensure that interconnection customers are able to interconnect to the

[644] CREA and NewSun Initial Comments at 46.

transmission system in a reliable, efficient, transparent, and timely manner. We note, however, that interconnection customers may request a material modification assessment under section 4.4 of the *pro forma* LGIP for reductions and that if those reductions are found to not be material, the interconnection customer may proceed with them without a loss of queue position.

h. **Fewer than Three Year Extension to Commercial Operation Date**

i. **NOPR Proposal**

288. Currently, if an interconnection customer's generating facility is delayed by fewer than three years, the *pro forma* LGIP states that such extensions are not material and shall be handled through construction sequencing. However, the *pro forma* LGIP does not state the starting point for this fewer than three-year period. In the NOPR, the Commission proposed to revise section 4.4.5 of the *pro forma* LGIP, which currently allows an extension of less than three cumulative years of the generating facility's commercial operation date, to require that the commercial operation date reflected in the initial interconnection request be used in calculating the permissible fewer than three-year extension.[645]

ii. **Comments**

289. Several commenters contend that the commercial operation dates set out in the executed LGIA, rather than the date in the initial interconnection request, are generally

[645] NOPR, 179 FERC ¶ 61,194 at P 71.

more accurate[646] and provide more certainty when established at the end of the interconnection study process as they would include the schedule estimates for network upgrades,[647] and the interconnection customer may have greater control over pursuing its development timeline.[648]

290. Invenergy argues that, because assigned upgrades necessary for interconnection can require more than three years for construction, it would be reasonable to permit a greater extension right of five years from the date set out in the LGIA.[649] Enel also argues that the Commission should grant a longer extension of time if the transmission provider's studies are delayed or if more time is required to build network upgrades because these circumstances are beyond the interconnection customer's control.[650] Enel also recommends requiring the transmission provider to grant a day-for-day delay to the originally requested commercial operation date for any delays in the study process relative to the LGIP deadlines as well as due consideration for network upgrades that require more than 18 months to design, procure, and construct.

[646] Invenergy Initial Comments at 34; Ørsted Initial Comments at 8; Pine Gate Initial Comments at 65.

[647] Ørsted Initial Comments at 8.

[648] Invenergy Initial Comments at 34.

[649] *Id.*

[650] Enel Initial Comments at 18-19.

291. Ameren and PPL assert that continuing to provide a three-year extension of the commercial operation date would allow projects to move forward when they are not ready or viable.[651] APS believes that limiting the ability to suspend interconnection requests or extend the commercial operation date to instances of *force majeure*, including where a customer demonstrates specific timeline obstructions such as permit issuance or supply chain delays, is more in line with the proposals in the NOPR.[652]

292. NV Energy seeks clarification on how long an interconnection customer may extend its commercial operation date because the *pro forma* LGIP allows seven to 10 years from the initial interconnection request to construct.[653] NV Energy requests clarification on how the three-year suspension clause in the *pro forma* LGIA plays into the timeline for the commercial operation date. Pine Gate argues that any extension period from the commercial operation date be subject to the overall seven-year time period for achieving commercial operation.[654] Invenergy argues that the Commission should also make clear that the limits on the initial proposed in-service date that can be specified in an

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[651] Ameren Initial Comments at 10; PPL Initial Comments at 11.

[652] APS Initial Comments at 7-8 (citing *Midcontinent Indep. Transmission Sys. Operator, Inc.*, 120 FERC ¶ 61,293, at PP 23, 27 (2007)).

[653] NV Energy Initial Comments at 5-6. NV Energy states that it currently has several customers that requested to move well beyond the three-year time frame and that most of its interconnection customers use the full seven to 10-year window. *Id.* at 6.

[654] Pine Gate Initial Comments at 65. Pine Gate also reiterates its comments on the ANOPR, stating that the Commission should expand the interconnection customer's option to build. *Id.* at 63 (citing Comments of Pine Gate, Docket No. RM21-17-000, at 9-10 (filed Oct. 12, 2021) (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 85, 353)).

interconnection request to no more than seven years beyond the interconnection request date, does not limit the ability to take advantage of commercial operation date extensions that are otherwise provided under the *pro forma* LGIP or an LGIA.[655] For example, some transmission owners have taken the position that, when exercising a suspension right, if the suspension would result in an in-service date greater than seven years after the date specified in the interconnection request, the interconnection customer cannot use its full suspension period. Invenergy asserts that the Commission has already clarified that the interconnection request limitation on proposed in-service dates is applicable only for the purpose of limiting the date requested at the application stage, and does not limit in-service dates that extend beyond that period as a result of other factors, which would include transmission owner delay, exercise of suspension, and here, additional commercial operation date extensions.[656] Invenergy also states that the Commission should clarify that its revisions to *pro forma* LGIP section 4.4.5 are in addition to, and do not limit, an interconnection customer's suspension rights under its interconnection agreement.[657]

iii. <u>Commission Determination</u>

293. We adopt the proposed revisions to section 4.4.5 of the *pro forma* LGIP that require that interconnection customers receive an extension of fewer than three

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[655] Invenergy Initial Comments at 35 (citing *pro forma* LGIP section 3.4.1 and *pro forma* LGIA art. 5.16).

[656] *Id.* (citing *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,180, at P 23 (2015)).

[657] *Id.* at 34.

cumulative years of the generating facility's commercial operation date without requiring them to request such an extension from the transmission provider. In response to commenters' concerns, however, we modify our proposal to clarify that the commercial operation date reflected in the initial interconnection request shall be used in calculating the permissible fewer than three-year extension until the interconnection customer executes, or requests the unexecuted filing of, an LGIA. Once the interconnection customer has executed an LGIA or requested that the LGIA be filed unexecuted, the commercial operation date established in the LGIA shall be the date from which the up to three cumulative years is calculated.

294. At the time the *pro forma* LGIP was adopted, the interconnection process was considerably shorter than it is now; the delays and sizeable interconnection queues facing transmission providers create a situation where many interconnection customers use this up to three-year period to ensure that their proposed generating facilities reach commercial operation. Furthermore, the length of the interconnection queues is such that at the time an interconnection customer enters the queue, it may have little idea of how long it will spend in the interconnection queue before commencement of the construction of its generating facility and required interconnection facilities and network upgrades. Thus, we agree with Invenergy, Ørsted, and Pine Gate, and we modify our proposal to require the up to three-year period to commence from the commercial operation date established in the interconnection customer's LGIA once the LGIA is executed or the interconnection customer has requested that it be filed unexecuted with the Commission.

295. We decline commenters' requests to revise the actual length of the permissible extension of a proposed generating facility's commercial operation date. The Commission did not propose to change the length of the permissible extension in the NOPR, and we lack an adequate record that the existing up to three-year extension is unjust and unreasonable.

296. Commenters request clarification[658] of how the changes to *pro forma* LGIP section 4.4.5 adopted in this final rule affect other provisions such as *pro forma* LGIP section 3.4.2 and *pro forma* LGIA article 5.16, which provide for extensions of the in-service date or suspension of construction.[659] We reiterate that the revisions to section 4.4.5 of the *pro forma* LGIP adopted in this final rule establish only the starting point for the less than three-year extension to the commercial operation date. The Commission did not propose in the NOPR, and we do not adopt in this final rule, changes to the extension of in-service date provisions in *pro forma* LGIP section 3.4.2, or to the suspension provision in *pro forma* LGIA article 5.16.

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[658] Invenergy Initial Comments at 35; NV Energy Initial Comments at 5-6.

[659] Specifically, *pro forma* LGIP section 3.4.2 (previously *pro forma* LGIP section 3.4.1) provides that the expected in-service date of the new generating facility or increase in capacity of the existing generating facility shall not exceed seven years, but may be extended up to 10 years upon mutual agreement of the transmission provider and interconnection customer. *Pro forma* LGIA article 5.16 provides the interconnection customer the right to suspend work by the transmission provider associated with the construction and installation of transmission provider's interconnection facilities and/or network upgrades for up to three years, at which time the LGIA would be deemed terminated.

i. Cluster Study Provisions (*Pro Forma* LGIP Sections 6, 7)

i. NOPR Proposal

297. As part of the proposed revisions to the *pro forma* LGIP, the NOPR proposed to replace section 6 (Interconnection Feasibility Study) with the new requirements to publicly post interconnection information, i.e., the "heatmap" as discussed above in Section III.A.1.c, thereby removing the entirety of the feasibility study from the *pro forma* LGIP.[660] Furthermore, in the NOPR, the Commission proposed to rename *pro forma* LGIP section 7 from "interconnection system impact study" to "cluster study."[661] The Commission proposed revisions to *pro forma* LGIP section 7.1 (Cluster Study Agreement) to state that the transmission provider must tender to each interconnection customer that submitted a valid interconnection request a cluster study agreement no later than five business days after the close of the cluster request window.[662] The Commission proposed revisions to *pro forma* LGIP section 7.2 (Execution of Cluster Study Agreement) to state that if the interconnection customer does not provide technical data when it delivers the cluster study agreement, the transmission provider must notify the interconnection customer of the deficiency within five business days, and the interconnection customer must cure the deficiency within 10 business days of receipt of

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[660] Proposed *pro forma* LGIP section 6.

[661] NOPR, 179 FERC ¶ 61,194 at P 74.

[662] Proposed *pro forma* LGIP section 7.1.

the notice.[663] The Commission proposed revisions to *pro forma* LGIP section 7.3 (Scope of Cluster Study Agreement) to make clear that the stability analysis, power flow analysis, and short circuit analysis previously conducted under the feasibility and system impact studies would be conducted on a clustered basis.[664] The Commission also proposed changes to *pro forma* LGIP section 7.3 to make clear that, for purposes of determining necessary interconnection facilities and network upgrades, the cluster study shall use the level of interconnection service requested by interconnection customers in the cluster, except where the transmission provider otherwise determines that it must study the full generating facility capacity due to safety or reliability concerns. The Commission proposed revisions to *pro forma* LGIP section 7.4 (Cluster Study Procedures) to state that, within 10 business days of simultaneously furnishing a cluster study report and a draft facilities study agreement to each interconnection customer within the cluster and posting such report on OASIS, the transmission provider shall convene an open meeting to discuss the study results and shall, upon request, make itself available to meet with individual interconnection customers after the report is provided.[665] *Pro forma* LGIP section 7.4 also states that the transmission provider must complete the cluster study within 150 calendar days. The Commission proposed revisions to *pro forma* LGIP section 7.5 (Cluster Study Restudies) to state that the

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[663] *Id*. at section 7.2.

[664] *Id*. at section 7.3.

[665] *Id*. at section 7.4.

interconnection customer must provide, within 20 calendar days after the cluster study report meeting, a study deposit, demonstration of site control, and a commercial readiness demonstration. *Pro forma* LGIP section 7.5 also states that the transmission provider must complete the cluster restudy within 150 calendar days and delineates the steps the transmission provider must take when a restudy is required or not required.[666]

ii. Comments

298. MISO supports the deletion of section 6 of the *pro forma* LGIP and the removal of the feasibility study from the *pro forma* LGIP.[667]

299. In reference to the proposed revisions to section 7.1 (Cluster Study Agreement) of the *pro forma* LGIP, Tri-State stresses that five business days is a tight time frame to tender a valid cluster study agreement to each interconnection customer that submitted a valid interconnection request and argues that this timeline is not feasible for transmission providers with greater than 50 interconnection requests submitted in a cluster request window.[668]

300. In reference to the proposed revisions to section 7.2 of the *pro forma* LGIP, Tri-State asserts that the Commission needs to confirm or reiterate that the interconnection

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[666] *Id*. at section 7.5.

[667] MISO Initial Comments at 40.

[668] Tri-State Initial Comments at 31.

request is considered withdrawn if the interconnection customer does not cure a deficiency identified by the transmission provider.[669]

301. In reference to the proposed revisions to section 7.3 (Scope of Cluster Study) of the *pro forma* LGIP, Tri-State asks the Commission to add language to address situations with studies pending completion of higher-queued project cluster studies.[670]

302. Enel proposes an alternative method for performing the cluster study and restudy to the NOPR proposal.[671] Enel states that if the Commission wants to retain the full scope of analyses in the cluster study, the Commission could require draft power flow analyses to be provided to interconnection customers part way through the cluster study. Enel explains that interconnection customers could be granted the right to reduce interconnection service amounts and make other changes pursuant to *pro forma* LGIP section 4.4.1 following receipt of these results. Enel states that the transmission provider would repeat the power flow analyses until the queue stabilized, with the motivation for interconnection customers to make changes in a timely way being driven by knowledge that once the latter portion of the studies started, the interconnection customer would lose this flexibility.

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[669] *Id.*

[670] *Id.*

[671] Enel Initial Comments at 17.

303. In the list of requirements to proceed to the cluster restudy in proposed revisions to section 7.5 of the *pro forma* LGIP, Enel proposes to add "(d) election of project changes as permitted by LGIP section 4.4.1."[672]

304. In the proposed revisions to section 7.5 of the *pro forma* LGIP, Enel suggests removing item (2), which states that if there are no changes to the composition of the cluster, a cluster restudy is not required, because it claims that the cluster restudy would always be required, at least in part, to add short circuit and stability analyses.

305. With regard to the 150-day cluster study deadline, some commenters generally support the proposed 150-day deadline to complete the cluster study.[673] Enel recommends a reduction in the scope and schedule of the cluster study to only include power flow analysis and a short circuit ratio test (to test grid strength and flag potential inverter instability issues) and suggests that this initial cluster study be completed in 90 days instead of 150 days.[674] Enel contends that, the availability of some information from this first study, interconnection customers retain more flexibility up to the point of committing to the initial cluster restudy, which allows interconnection customers to optimize the characteristics of their proposed generating facilities, most notably the amount of ERIS and NRIS interconnection service requested, in response to the results of

[672] *Id.*

[673] AEE Initial Comments at 33; Clean Energy Associations Initial Comments at 20-21; Consumers Energy Initial Comments at 4.

[674] Enel Initial Comments at 15-16.

the study. Enel argues that early flexibility for optimization of proposed generating facilities is better than forcing interconnection customers to withdraw and re-enter the interconnection queue, is less disruptive, and does not add a year of delay to an interconnection customer completing the interconnection process.

306. A number of commenters argue that the proposed 150-day deadline to complete the initial cluster study may be, or is, too short and recommend a longer study window.[675] A few commenters also argue that the study timelines are too short, given the proposal to eliminate the reasonable efforts standard and impose penalties on transmission providers that miss those deadlines.[676] National Grid asserts that the proposed 150-day deadline may be "unreasonably condensed" and could result in a decline in the quality of the studies, which could lead to delays.[677] Specifically, National Grid claims that rushing the issuance of the cluster study could lead to later amendments or corrections to certain engineering requirements or cost estimates, that in turn may lead to later-stage interconnection request withdrawals.

307. Tri-State notes that it currently implements a 270-day system impact study period, specifically 150 days for phase 1 (power flow, short circuit, reactive capability) and 120 days for phase 2 (short circuit, transient stability), and has yet to miss a study

[675] APS Initial Comments at 8; AES Initial Comments at 9; ISO-NE Initial Comments at 23; National Grid Initial Comments at 13-14; Tri-State Initial Comments at 10.

[676] Dominion Initial Comments at 18; Tri-State Initial Comments at 4.

[677] National Grid Initial Comments at 13-14.

deadline.[678] Tri-State argues that this time frame allows for a thorough study process, including coordination with neighboring systems and the correction of errors found in interconnection customers' modeling data.

308. AES contends that cluster study timelines should be tailored to the types of studies being completed at each stage of the respective cluster.[679] For example, AES states that steady state analysis takes less time to complete than dynamic analysis, meaning that a longer time frame should be afforded for dynamic analysis in the cluster study process. Accordingly, AES recommends that the Commission adopt a 150-day general study timeline for cluster studies and restudies (system impact study-steady state, and short-circuit analysis performed) and a 200-day timeline for facilities studies (dynamic analysis performed).

309. APS requests that the Commission extend the initial study time frame to 180 days to provide meaningful studies identifying feasible proposed generating facilities, explaining that the APS transmission system is situated in such a way that many interconnections are at jointly owned facilities that require reviews and sign-off from multiple owners, including non-jurisdictional entities.[680] APS argues that 180 days is more prudent for initial studies, with the exception of specific criteria such as jointly owned facilities, Western Electricity Coordinating Council (WECC) rated paths, and

[678] Tri-State Initial Comments at 10.

[679] AES Initial Comments at 9.

[680] APS Initial Comments at 8-9.

federally owned and Tribal lands, for which studies take significantly longer despite good faith efforts.

310. NYTOs and National Grid argue that the proposal is not clear on which specific steps would be included in the 150-day time frame for the initial cluster study and argue that certain additional special studies that a transmission provider may need to perform should not be subject to a 150-day time frame.[681] NYTOs state that it is unclear when the clock starts for the proposed 150-day cluster study deadline and how the scope of the work can be reasonably limited to comply with the 150-day deadline.[682] NYTOs argue that transmission providers and transmission owners should be afforded the flexibility to provide clarifications and supporting details on compliance.

311. Similarly, National Grid notes that certain RTO/ISO interconnection processes require special supplemental studies in addition to general system impact studies and that, while the NOPR recognizes that these studies may be required to ensure reliable interconnection of new generating facilities, it does not address whether such studies must be conducted within the proposed 150-day cluster study window or could be conducted outside of this window.[683] National Grid argues that the time to complete such special studies should not be included in the NOPR's proposed 150-day cluster study window and that the final rule should allow regions to adjust their overall interconnection

[681] National Grid Initial Comments at 15; NYTOs Initial Comments at 15.

[682] NYTOs Initial Comments at 15.

[683] National Grid Initial Comments at 15.

timelines to accommodate such region-specific studies and take into consideration the time required to develop system models. Finally, National Grid states that the NOPR does not address whether the 150-day cluster study window includes the time required to develop system models and base case data for the cluster study.

312. Several commenters recommend that the Commission provide transmission providers with flexibility to specify study timelines.[684]

313. Regarding the 150-day cluster restudy deadline, several commenters agree that the 150-day deadline is reasonable for a cluster restudy.[685] Other commenters oppose the 150-day deadline. Bonneville argues that the proposed requirement to conduct a cluster restudy within 150 days is unworkable because the complexity of the cluster restudy would vary and directly impact the completion timeline.[686] Therefore, Bonneville seeks a longer time frame.

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[684] AEP Initial Comments at 17-18; APPA-LPPC Initial Comments at 21; Avangrid Initial Comments at 13; Bonneville Initial Comments at 16; CAISO Initial Comments at 11; Dominion Initial Comments at 16-17; Indicated PJM TOs Reply Comments at 39; ISO-NE Initial Comments at 35-37; NYISO Initial Comments at 29, 33; NY Commission and NYSERDA Initial Comments at 5; NYTOs Initial Comments at 14; SEIA Reply Comments at 6.

[685] AES Initial Comment at 11; APS Initial Comments at 8; ISO-NE Initial Comments at 23.

[686] Bonneville Initial Comments at 9.

314. On the other hand, several commenters argue that the deadline to conduct a cluster restudy should be shorter.[687] AES recommends that the Commission instead require transmission providers to include restudies and model rebuilds between cluster study phases, and to require that the timeline for such model rebuilds and restudies cannot be greater than 90 days.[688] Enel similarly asserts that if the Commission leaves the cluster study timeline at 150 days and does not change the study scope, the timeline for cluster restudies should be 90 days.[689]

315. A few commenters argue that a 30-day window per restudy is more reasonable because network models are already built, and therefore substantially fewer staff resources should be required than for the initial study.[690] Cypress Creek adds that a shorter restudy window will also help avoid potential delays in a cluster study process in which multiple restudies are required.[691] AEE also recommends that the Commission limit interconnection restudy timelines to 30 days, arguing that this will encourage transmission providers to treat customers in interconnection restudy with the same urgency as customers in the initial interconnection study, eliminating the possibility of

[687] AEE Initial Comments at 33; Clean Energy Associations Initial Comments at 42; Cypress Creek Initial Comments at 18.

[688] AES Initial Comments at 11.

[689] Enel Initial Comments at 83.

[690] AEE Reply Comments at 11-12; Clean Energy Associations Initial Comments at 42; Cypress Creek Initial Comments at 18; SEIA Initial Comments at 8.

[691] Cypress Creek Initial Comments at 18.

asymmetric treatment of interconnection customers and alleviating interconnection queue congestion by moving those interconnection customers that have been in the interconnection queue the longest to study completion.[692]

iii. Commission Determination

316. We adopt the proposed deletion of the feasibility study as effectuated by the replacement of the current section 6 (Interconnection Feasibility Study) of the *pro forma* LGIP with the new heatmap requirements, as discussed in Section III.A.1.c. The move from a serial interconnection process to the new cluster study process, coupled with the Commission's heatmap requirements, render the feasibility study redundant at best and an unnecessary burden on transmission provider resources. As discussed in Section III.A.1.c, above, we find that the publicly available information required by this final rule will provide the appropriate level of pre-interconnection queue information for interconnection customers to make informed choices.

317. We also adopt, with one modification, the proposed revisions to section 7 of the *pro forma* LGIP that rename it "cluster study" instead of "interconnection system impact study," which set out the requirements and scope of the cluster study agreement, as well as the cluster study and restudy procedures. These revisions reflect the adoption of the cluster study process set forth in this final rule by making clear that the interconnection studies that transmission providers previously performed as part of the serial system impact studies (i.e., stability analysis, power flow analysis, and short circuit analysis)

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[692] AEE Initial Comments at 33.

must now be conducted on a clustered basis. As discussed further in Section III.A.6 of this final rule, *pro forma* LGIP section 7.5 is modified to remove the requirement to provide an initial study deposit that would have been applied towards the cost of the cluster study process.

318. We are not persuaded by Tri-State's concern that five business days after the close of the cluster request window is too short a time frame for a transmission provider to tender a cluster study agreement to each interconnection customer. Transmission providers may start to prepare cluster study agreements before the close of the cluster request window, as the overall terms and conditions of the cluster study agreement are standardized so that a transmission provider need not engage in rewriting each agreement before tendering a draft to the interconnection customer.

319. In response to Tri-State's comments concerning section 7.2 of the *pro forma* LGIP, we confirm that an interconnection request is considered withdrawn if the interconnection customer does not cure deficiencies identified by the transmission provider. We note that under new section 3.4.4 of the *pro forma* LGIP, if a transmission provider identifies that an interconnection customer's technical data are incomplete or contain errors, both parties must "work expeditiously and in good faith to remedy such issues," but the failure by the interconnection customer to provide the missing data or correct data errors will be treated as a withdrawal and dealt with under *pro forma* LGIP section 3.7 (Withdrawal).

320. In reference to Tri-State's comments on the proposed revisions to section 7.3 of the *pro forma* LGIP, we decline to add language to address situations with studies

pending completion of higher-queued project cluster studies because Tri-State's comments are unclear as to what additional language may be needed.

321. We decline to adopt the alternative methods to perform cluster studies and restudies suggested by Enel. The current *pro forma* LGIP does not prescribe particular study methods and instead provides discretion to transmission providers to determine the particular methods of study appropriate for their transmission systems. We do not, based on the record in this proceeding, find a basis to determine that existing study methods are unjust, unreasonable, and unduly discriminatory or preferential. We also decline to add Enel's suggested section (d) to section 7.5 of the *pro forma* LGIP. *Pro forma* LGIP section 4.4.1 contains the modifications permitted to an interconnection request prior to the return of an executed cluster study agreement, which predates any potential cluster restudy. We further note that the record does not support Enel's modification request.

322. We decline to adopt the provision requiring transmission providers to hold cluster study report meetings with individual customers as proposed in section 7.4 of the *pro forma* LGIP. We find that the individual meetings would be unnecessary, and that individual customers should utilize the group cluster study report meeting as a more efficient forum in which to address any questions or concerns pertaining to the cluster study report. We also find that requiring transmission providers to conduct individual meetings would impose unnecessarily burdensome additional requirements on transmission providers and would be insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

323. Also, we decline to remove proposed section 7.5(2) of the *pro forma* LGIP, as suggested by Enel. Contrary to Enel's claim, *pro forma* LGIP section 7.3 establishes that the cluster study will consist of short circuit and stability analyses; therefore, we disagree with Enel that a cluster restudy will be needed in all cases to perform the short circuit and stability analyses. Section 7.5(2) states that if there are no changes to the composition of the cluster, a cluster restudy is not required. We find that this is appropriate as it prevents the transmission provider from performing an unnecessary restudy if no conditions have changed after the first cluster study. This will increase efficiency, free up the transmission provider's resources to perform other studies, and increase the speed of interconnection, ensuring that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

324. Based on the record, we find that a 150-calendar day cluster study deadline provides a sufficient time to allow transmission providers to perform the stability analyses, power flow analyses, and short circuit analyses required in the cluster study process for complex clusters consisting of numerous interconnection requests. We find that the 150-calendar day time frame balances providing transmission providers with sufficient time to perform these technical cluster studies while providing certainty about the timeline for the interconnection process and ensuring that cluster studies progress in a timely manner. We note that depending on the cluster size, cluster studies may not always consume the entire 150 calendar days, and if a cluster study is complete prior to this deadline, transmission providers have flexibility to provide the cluster study report at that time prior to the deadline indicated in its LGIP and commence any necessary

restudies or move to the facilities study phase. We also note that if a transmission provider progresses to the next study phase prior to the deadline indicated in its LGIP, the transmission provider must post any changes on its website or OASIS.

325. We disagree with Enel's suggestion to reduce the scope and schedule of the cluster study in the proposed *pro forma* LGIP. The cluster study represents the first time the interconnection customer will obtain information about its potential interconnection costs. At this point, interconnection customers will have to make significant financial decisions about whether to remain in the interconnection queue. The information provided in the cluster study report will likely dictate that decision, and we find that the scope of the study is appropriate to allow interconnection customers to make these types of decisions and evaluate whether they will face significant risk. Given that we decline to reduce the scope of the study, we find Enel's request to reduce the timeline overly restrictive. Enel's proposal would create significant burden on transmission providers to perform complex studies in an even shorter timeline, and we therefore decline to adopt it.

326. We also disagree with commenters that argue that the 150-calendar day time frame to complete the cluster study is too short. As discussed above, numerous commenters agree with the Commission's conclusion that the significant interconnection queue backlogs create uncertainty and risk in bringing new generating facilities online, rendering Commission-jurisdictional rates unjust and unreasonable. While we have extended the timeline from that provided in the individual serial study process, we believe that 150 calendar days is a reasonable extension to account for the more complex study. We also note that transmission providers will be conducting only one interconnection study, or at

most a small number of interconnection studies, at a time, allowing them to devote more resources to completing the studies in a timely manner. Thus, on balance, we believe that 150 calendar days represents an appropriate and reasonable timeline on which transmission providers must complete initial cluster studies.

327. We disagree with NYTOs that it is not clear as to when the clock starts for the proposed 150-calendar day cluster study deadline, as proposed *pro forma* LGIP section 7.3 contains this information (150 calendar days from the close of the customer engagement window). We also disagree with NYTOs' statement that it is not clear how the scope of the work can be reasonably limited to comply with the 150-calendar day deadline, as we are not proposing to limit the scope of work necessary to effectively run a cluster study. As discussed above, we find that the 150-calendar day cluster study deadline, combined with the fewer necessary studies, provides a reasonable amount of time to allow transmission providers to perform the required studies.

328. In response to National Grid's concern that some RTO/ISO interconnection processes require supplemental studies and that these studies should not be required to be conducted within the 150-calendar day cluster study window, we decline to modify the *pro forma* LGIP to provide for more time for such studies. We also clarify for National Grid that the 150-calendar day deadline includes the time required to develop system models and base case data for the cluster study.

329. Regarding the 150-calendar day cluster restudy deadline, we agree with commenters that the proposed 150-calendar day deadline is reasonable for a cluster restudy. We acknowledge that some commenters argue that 150 calendar days is too

short, while others argue that it is too long. On balance, we find that 150 calendar days is a just and reasonable time frame for purposes of the *pro forma* LGIP that allows transmission providers to conduct potentially complex restudies for instances in which larger clusters experience multiple withdrawals and/or modifications.

330. In response to commenters' arguments that a 150-calendar day restudy deadline is too long, we note that if transmission providers complete the cluster restudy prior to the full 150-calendar day period elapsing, transmission providers may move to the facilities study stage at that time. As such, the adopted 150-calendar day cluster restudy time frame accommodates more complex instances of cluster restudies while still allowing flexibility for transmission providers to move forward without waiting for the deadline to pass if the restudy does not take the full 150 calendar days.

331. Additionally, we decline to adopt suggestions to allow transmission providers flexibility to set their own study deadlines,[693] which would undermine the purpose of ensuring that transmission providers complete interconnection studies by standard deadlines prescribed by their tariffs and would thus be insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

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[693] AEP Initial Comments at 17-18; APPA-LPPC Initial Comments at 21; Avangrid Initial Comments at 13; Bonneville Initial Comments at 16; CAISO Initial Comments at 11; Dominion Initial Comments at 16-17; Indicated PJM TOs Reply Comments at 39; ISO-NE Initial Comments at 35-37; NYISO Initial Comments at 29, 33; NY Commission and NYSERDA at 5; NYTOs Initial Comments at 14; SEIA Reply Comments at 6.

j. Restudies Triggered by Higher- or Equally Queued Generating Facility

i. NOPR Proposal

332. In the NOPR, the Commission proposed to revise section 8.5 (Restudy) of the *pro forma* LGIP to make clear that restudies can be triggered by a higher- or equally queued interconnection request withdrawing from the interconnection queue or modification of a higher- or equally queued interconnection request pursuant to section 4.4 (Modifications) of the *pro forma* LGIP.[694]

ii. Comments

333. Shell argues the withdrawal of an interconnection request should not automatically trigger a cluster restudy, and instead the Commission should consider a process and cost allocation method that creates a "secondary market" to replace a proposed generating facility that withdraws with another generating facility in the same location or nearby.[695] CREA and NewSun agree with Shell's suggestion to allow interconnection customers to step in and assume the rights of any interconnection customer that withdraws its interconnection request.[696] Similarly, R Street argues that the cluster study process should not impede the transfer of interconnection request "ownership," as, according to R

[694] NOPR, 179 FERC ¶ 61,194 at P 75.

[695] Shell Initial Comments, app. A at i.

[696] CREA and NewSun Reply Comments at 10.

Street, allowing parties to trade will help ensure an efficient balance between generation additions and transmission interconnection costs.[697]

334. MISO seeks clarification on the trigger for restudies. MISO states that its understanding is that any modification during its study process that is found to be material would not be allowed.[698] Further, MISO contends that allowing a material modification to impact an equally queued interconnection customer seems to be inconsistent with the Commission's proposal to modify the definition of material modification.[699] Therefore, MISO argues that there should not be a need for a restudy due to such modification. MISO asserts that the Commission should not allow modifications during the study process that materially impact other interconnection customers and may require restudies.

iii. **Commission Determination**

335. We adopt the proposed revisions to section 8.5 of the *pro forma* LGIP to make clear that restudies can be triggered by a withdrawal or modification by a higher- or equally queued interconnection request. First, we clarify that the "modification" we refer to in this section must be explicitly permitted under *pro forma* LGIP section 4.4. Any other modification that triggered a restudy would be found to be material and would not be allowed, as it would affect the cost and/or timing of the other customers in the

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[697] R Street Initial Comments at 11.

[698] MISO Initial Comments at 40.

[699] *Id.* (referencing NOPR, 179 FERC ¶ 61,194 at P 65).

interconnection queue by necessitating a restudy. Next, we find that restudies may be triggered if there is either a withdrawal or a modification explicitly permitted under *pro forma* LGIP section 4.4. Changes to the composition of the cluster often require the transmission provider to restudy the entire cluster to ensure that all network upgrades and the associated costs are still needed. Finally, we find that stating that restudy may be required due to the withdrawal or modification of a higher- or equally queued interconnection request, rather than requiring that a restudy must occur, provides the transmission provider with flexibility to assess whether the restudy is necessary. If the transmission provider is able to move forward without performing a full restudy, that is a preferable outcome in terms of interconnection queue efficiency, as the transmission provider can maintain the study milestones already achieved and maintain progress towards completion and operation for generating facilities in the cluster, as opposed to dedicating significant additional time required to restart and conduct the study process over again when it may not be necessary or beneficial to do so.

336. In response to Shell, CREA and NewSun, and R Street, we decline to consider modifications to the *pro forma* LGIP to create a "secondary market" process that would allow one generating facility to replace a similarly situated one that withdraws from the interconnection queue, where that withdrawal would otherwise trigger a restudy. The Commission did not propose such a process in the NOPR, and we do not have a sufficient record to consider adopting such a process in this final rule.

337. In response to MISO, we clarify that material modifications are defined in section 1 of the *pro forma* LGIP as modifications that have a material impact on the cost or

timing of any interconnection request with an equal or later queue position. Under section 4.4.3 of the *pro forma* LGIP, if an interconnection customer chooses to move forward with the modification that has been deemed material by the transmission provider, the interconnection customer will lose its queue position and must proceed with a new interconnection request if desired. However, we note that certain modifications as listed in *pro forma* LGIP sections 4.4.1, 4.4.2, and 4.4.5 are permitted regardless of their impact on other interconnection customers.

k. Timing of LGIA Tender, Execution, and Filing

i. NOPR Proposal

338. In the NOPR, the Commission proposed to revise sections 11.1 (Tender) and 11.3 (Execution and Filing) of the *pro forma* LGIP, which include provisions related to the tender, execution, and filing of the LGIA, to incorporate a 60 calendar-day negotiation period and to incorporate the site control demonstrations and LGIA deposit provisions included in proposed section 3 of the *pro forma* LGIP.[700]

ii. Comments

339. Enel states that many transmission providers and interconnection customers are confused as to how to interpret *pro forma* LGIP sections 11.1 and 11.2 in relation to each other, and Enel thus recommends that the Commission revise and simplify sections 11.1 and 11.2 of the *pro forma* LGIP to provide more clarity.[701] Enel argues that additional

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[700] NOPR, 179 FERC ¶ 61,194 at P 76.

[701] Enel Initial Comments at 13-14.

changes are needed to address common delays in completion of the final facilities study report; delays in a transmission provider issuing the draft LGIA; and delays in the transmission provider executing the LGIA after receiving the interconnection customer's signature and milestones, and subsequently proposes targeted revisions to *pro forma* LGIP sections 11.1 and 11.2 to provide additional time for interconnection customers to review and negotiate LGIAs.[702]

340. Tri-State notes that section 11.3 of the *pro forma* LGIP is unclear when it states that the "Transmission Provider must not suspend the LGIA" until the interconnection customer meets the tariff requirements because it is the interconnection customer that has the ability to suspend a proposed generating facility.[703]

341. APS requests that the Commission be more prescriptive on what is considered reasonable evidence of achieving development milestones when executing an LGIA in the same manner that the Commission defines commercial readiness milestones in order to avoid subjectivity and potential disagreements regarding what is considered "reasonable."[704] APS also asserts that the reference to simultaneous submission of the interconnection customer-executed LGIA and the continued demonstration of site control is duplicative and unnecessary if an interconnection customer demonstrates site control at the time an interconnection request is made.

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[702] *Id.* at 14-15.

[703] Tri-State Initial Comments at 32.

[704] ASP Initial Comments at 7.

342. Hydropower Commenters contend that the Commission should provide additional time for payment of interconnection costs after the interconnection process is complete.[705] Hydropower Commenters assert that once a transmission provider delivers the interconnection agreement and construction agreement to the interconnection customer, the interconnection customer has only 60 days to execute the agreements and 15 business days after receipt of the signed agreements to demonstrate site control or post a non-refundable additional security deposit to cover the interconnection costs. Hydropower Commenters argue that, because the end of the study process may occur long before a proposed generating facility is fully funded, and the interconnection customer risks losing its queue position if it does not execute the agreements, the Commission should extend this period to at least one year so the interconnection customer has time to secure funding and avoids having to restart the interconnection process.

343. NV Energy similarly suggests changes to the NOPR proposal to allow interconnection customers that request a transmission provider to file an unexecuted LGIA to satisfy these requirements within 15 days of the Commission issuing an order. NV Energy states that the proposed extra time between receiving a draft LGIA and having to satisfy these requirements creates an undue preferential advantage for those interconnection customers that request unexecuted LGIAs to be filed at the Commission

[705] Hydropower Commenters Initial Comments at 18.

and could delay the interconnection process for others.[706] To address this issue, NV Energy suggests that interconnection customers who choose to have their unexecuted LGIAs filed with the Commission should be required to submit their data to the transmission provider by the day after the filing of the LGIA.

iii. Commission Determination

344. We adopt, in part, and modify, in part, the proposal to revise sections 11.1 and 11.3 of the *pro forma* LGIP, regarding the tendering, execution, and filing of the LGIA, to incorporate a 60-calendar day negotiation period and to incorporate the site control demonstrations and LGIA deposit provisions included in proposed section 3 of the *pro forma* LGIP. We find that the revisions to section 11.1 of the *pro forma* LGIP that we adopt herein clarify the process of tendering an LGIA and the revisions to section 11.3 of the *pro forma* LGIP that we adopt herein incorporate the site control and LGIA deposit provisions adopted elsewhere in this final rule.

345. We do not adopt the proposed revisions to *pro forma* LGIP section 11.3 that reference the commercial readiness demonstration provisions of proposed section 8.1 of the *pro forma* LGIP because we are not adopting those provisions, as discussed below in Section III.A.6.

346. We modify the proposed revisions to *pro forma* LGIP section 11.3, as requested by Tri-State, because we agree that the proposal was unclear when it stated that "Transmission Provider must not suspend the LGIA under LGIA article 5.16" until the

[706] NV Energy Initial Comments at 20.

interconnection customer meets certain tariff requirements. We modify *pro forma* LGIP section 11.3 to instead state: "Interconnection Customer may not request to suspend its LGIA under LGIA Article 5.16 until Interconnection Customer" meets certain tariff requirements. This reflects the fact that it is the interconnection customer, not the transmission provider, that has the right to suspend the LGIA.

347. We also modify proposed section 11.3 of the *pro forma* LGIP in response to NV Energy's concerns about favoring interconnection customers that request a transmission provider to file an unexecuted LGIA. We agree that the proposal has the potential to encourage more filings of unexecuted LGIAs simply to delay the due date for submission of deposits, evidence of site control, and milestone progress data. We therefore modify the proposal such that interconnection customers that request a transmission provider to file an unexecuted LGIA must satisfy these submission requirements within 10 business days after the date of the filing of the unexecuted LGIA with the Commission.

348. We decline to make further modifications to the proposal beyond those discussed above. Enel has neither explained why *pro forma* LGIP sections 11.1, as revised by this final rule, and 11.2, cause an unjust and unreasonable result for interconnection customers, nor has it explained why changes to the negotiation process between transmission providers and interconnection customers are needed at this time.

349. Similarly, we decline APS' request that the Commission be "more prescriptive" on what is considered reasonable evidence of achieving development milestones when executing an LGIA. We believe that the requirement that interconnection customers

provide reasonable evidence is sufficient to ensure just and reasonable rates without imposing detailed requirements surrounding the meaning of "reasonable." There is inadequate record to demonstrate a more prescriptive approach is needed. For example, development milestones generally involve the execution of contracts or applications for permits.

350. We also decline to adopt Hydropower Commenters' request to modify the *pro forma* LGIP to provide additional time for payment of interconnection costs after the conclusion of the interconnection study process. The *pro forma* LGIP, as modified by this final rule, requires transmission providers to give interconnection customers ample notice of costs and the timing that costs are due as part of the interconnection process so that interconnection customers can secure funding for a proposed generating facility. We are unpersuaded that interconnection customers should have additional time beyond that already provided, especially given the number of generating facilities that have been developed using the existing process and the added transparency that we adopt in this final rule that will only serve to improve the ability of interconnection customers to secure financing.

l. Cluster Subgroups

i. NOPR Proposal

351. In the NOPR, the Commission sought comment on whether to require transmission providers to conduct cluster studies on subgroups of interconnection customers based on areas of geographic and electric relevance, and, if so, whether to

adopt provisions governing how cluster areas should be formed to ensure that cluster areas are formed in a transparent and not unduly discriminatory manner.[707]

ii. **Comments**

352. A number of commenters support permitting transmission providers to study clusters in subgroups based on geographic or electrical relevance,[708] but some argue that clustering projects in subgroups should not be required.[709]

353. Several entities argue that clustering around subgroups of geographic or electrical relevance is a reasonable approach, particularly for transmission providers with a large or fragmented footprint.[710] Some commenters argue that creating sub-clusters may not make sense for transmission providers with small footprints.[711] Several commenters argue that transmission providers should have flexibility in deciding whether to form subgroups of interconnection customers because geographic and electric relevance will vary with each cluster study.[712] Similarly, some commenters contend that the

[707] NOPR, 179 FERC ¶ 61,194 at P 77.

[708] APS Initial Comments at 9; ClearPath Initial Comments at 7; NARUC Initial Comments at 6; NextEra Initial Comments at 14-15; Ørsted Initial Comments at 8; PacifiCorp Initial Comments at 17; Pennsylvania Commission Initial Comments at 8.

[709] APS Initial Comments at 9; Indicated PJM TOs Initial Comments at 18; NextEra Initial Comments at 15; PJM Initial Comments at 22.

[710] Illinois Commission Initial Comments at 5; NextEra Initial Comments at 14-15; PacifiCorp Initial Comments at 18; Pennsylvania Commission Initial Comments at 8.

[711] NRECA Initial Comments at 19; Tri-State Initial Comments at 11.

[712] Bonneville Initial Comments at 8-9; ClearPath Initial Comments at 8; ENGIE Reply Comments at 2; Fervo Energy Reply Comment at 4; Indicated PJM TOs Initial

Commission should not mandate studying subgroups based on geographic and electric relevance, and that the efficacy of this approach should instead first be evaluated through experience.[713]

354. PacifiCorp notes that using cluster study areas allows it to assess and more efficiently allocate the costs of network upgrades to requesters triggering the improvements and protect interconnection customers in different clusters from bearing the cost of network upgrades triggered by interconnection customers in different parts of PacifiCorp's system, thereby facilitating more expedient processing of all the cluster studies.[714] PacifiCorp asserts that its ability to create cluster areas where appropriate is a critical feature of its cluster study process, adding that cluster areas can facilitate expedient processing of interconnection requests that might otherwise be delayed due to restudies or other study complications.[715]

355. On the other hand, Pattern Energy asserts that designating subregions may result in separate geographic regions bearing a disproportionate share of network upgrade costs that provide regional benefits and should be subject to regional cost allocations.[716] Pattern Energy notes that it is also important for the transmission provider to review

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Comments at 18; SEIA Reply Comments at 6.

[713] AES Initial Comments at 10; PJM Initial Comments at 22.

[714] PacifiCorp Initial Comments at 18-19.

[715] *Id.* at 17.

[716] Pattern Energy Initial Comments at 16.

subregional cluster study results and determine whether inter-cluster network upgrades would better serve the needs of the subregional clusters during each planning cycle. Illinois Commission asserts that interconnection requests that are near one another might have a greater impact on each other, and subgroups could ease the study process, but any subgroup process should not compromise cost or timing efficiency gains that the clustering process is meant to address.[717] OPSI argues that to reduce the "first mover disadvantage" most effectively, the Commission should continue to analyze and further explain in any final rule whether a region-wide, annual cluster in a large region like PJM could benefit from better defined subclusters.[718] OPSI asserts that the Commission should further evaluate methods to ensure that clusters facilitate identification of shared network upgrades by grouping generating facilities based on areas of geographic and electrical relevance.

356. Avangrid contends that the open call cluster request window should have geographic distinctions, but that if the open call results in only one interconnection request in a particular area of the system electrically, this interconnection should be able to undergo a process reminiscent of current serial study processes in a parallel track if it will influence, or be influenced by, the broader cluster study process.[719]

[717] Illinois Commission Initial Comments at 5.

[718] OPSI Initial Comments at 4.

[719] Avangrid Initial Comments at 12.

357. Some commenters argue that the Commission should set forth specific mandates to transmission providers on how cluster areas should be formed.[720] CREA and NewSun argue that clear mandates would prevent transmission providers from subgrouping as a means to engage in anti-competitive conduct (e.g., assigning the utility's own generation to subgroups with lower congestion or network upgrade costs).[721] Similarly, Fervo Energy contends that the Commission should adopt provisions governing how cluster areas should be formed to ensure that clusters are formed in a transparent and not unduly discriminatory manner.[722]

358. Other commenters argue that the Commission should provide flexibility by creating a general framework for defining cluster study subgroups appropriate for their own regions, rather than a specific set of requirements.[723] Some commenters further contend that transmission providers have extensive knowledge of their own transmission

[720] CREA and NewSun Initial Comments at 48-49; Environmental Defense Fund Reply Comments at 7-8; Fervo Energy Initial Comments at 3.

[721] CREA and NewSun Initial Comments at 48-49.

[722] Fervo Energy Initial Comments at 3.

[723] APS Initial Comments at 9; Clean Energy Associations Initial Comments at 20; ClearPath Initial Comments at 8; EEI Initial Comments at 5; Eversource Initial Comments at 13-14; LADWP Initial Comments at 3; Longroad Energy Initial Comments at 10; MISO Initial Comments at 41-42; New York State Department Initial Comments at 5-6; Pattern Energy Initial Comments at 15; PacifiCorp Initial Comments at 18; PPL Initial Comments at 10; R Street Initial Comments at 11; Tri-State Initial Comments at 11; U.S. Chamber of Commerce Initial Comments at 7; Xcel Initial Comments at 23.

systems,[724] and the particular interconnection requests that should and should not be included within a cluster based on their system's geography, electric configuration, or other relevant factors.[725] A number of commenters suggest that transmission providers develop subgroup criteria with stakeholder input.[726]

359. Other commenters argue that the Commission should allow variation in how transmission providers form clusters. For example, R Street argues that the Commission should refrain from being too prescriptive regarding how cluster areas are defined, and instead require that transmission providers publish their cluster definitions well in advance of the request window for interconnection requests.[727] Clean Energy States believe that allowing interconnection customers to create their own clusters would result in an internal vetting of proposed generating facilities in the cluster and negotiation about how costs and penalties will be managed.[728] Regarding how clusters should be defined, several commenters provide suggestions for subgroup criteria beyond geographic proximity or electrical relevance.[729] PPL suggests cluster formation be based on

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[724] Shell Initial Comments, app. A at i; Tri-State Initial Comments at 11.

[725] U.S. Chamber of Commerce Initial Comments at 7.

[726] Interwest Initial Comments at 14; MISO Initial Comments at 42; Northwest and Intermountain Initial Comments at 7; Pattern Energy Initial Comments at 15-16; PacifiCorp Initial Comments at 18 (citing PacifiCorp, Transmission OATT and Service Agmts, Part IV.42.4(a) (5.0.0)); Shell Initial Comments, app. A at i.

[727] R Street Initial Comments at 11.

[728] Clean Energy States Initial Comments at 10.

[729] *Id.* at 5; Fervo Energy Initial Comments at 3; Interwest Initial Comments at 13-

geographic or electrical proximity only and that interconnection customers should not be separated based on fuel type.[730] Energy Keepers asserts that, when utilities are considering cluster studies on subgroups of interconnection customers, those clusters should be based on location.[731] Clean Energy Associations, Vistra, and ENGIE assert that cluster studies should evaluate subgroups of projects based on electric proximity to one another.[732] Further, ENGIE agrees that distribution factors should not be the sole indicator of electrical proximity as there are other factors around which subgroups might appropriately be grouped.[733]

360. Xcel argues that it is not necessary to create "separate" clusters for electrically distinct regions, noting that PSCo separates interconnection requests into "study pockets" based on geographic/electrical separation but studies all the interconnection requests in a single cluster.[734]

361. Clean Energy Associations assert that the Commission should make clear whether a cluster study must identify the upgrades required in order to interconnect every

14; Longroad Energy Initial Comments at 10; Pattern Energy Initial Comments at 15-16; Pennsylvania Commission Initial Comments at 6.

[730] PPL Initial Comments at 10.

[731] Energy Keepers Initial Comments at 4.

[732] Clean Energy Associations Initial Comments at 20; ENGIE Reply Comments at 2; Vistra Initial Comments at 2.

[733] ENGIE Reply Comments at 2.

[734] Xcel Initial Comments at 23.

interconnection request in whole, or whether it might identify upgrades that would be sufficient for only a subset of the interconnection requests; if the latter, Clean Energy Associations continue, the Commission should establish a *pro forma* process for determining which requests might proceed with those initial upgrades.[735] Clean Energy Associations claim that transmission development is a "lumpy" process, and in some cases there can be "breakpoints" where adding one more generating facility can result in a significant per-unit cost increase compared to the interconnection costs that could have been achieved for a subset of the interconnection requests up to that point. Clean Energy Associations state that, in the current ISO-NE cluster study process, ISO-NE attempts to identify such breakpoints and fills each cluster up to that level, with remaining requests able to either withdraw or proceed into the next cluster study. Some commenters contend that studies should include or consider including breakpoints, which can provide helpful information to inform interconnection customers' next steps.[736]

362. Finally, several commenters encourage transparency and request that any subgrouping criteria be publicly posted or filed by transmission providers or RTOs/ISOs.[737]

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[735] Clean Energy Associations Initial Comments at 26.

[736] *Id.* at 26-27; SEIA Reply Comments at 6.

[737] ENGIE Reply Comments at 2; Fervo Energy Initial Comments at 3; Fervo Energy Reply Comments at 4; Ørsted Initial Comments at 8; R Street Initial Comments at 11; Tri-State Initial Comments at 11.

iii. <u>Commission Determination</u>

363. We will neither require transmission providers to conduct cluster studies on subgroups of interconnection customers based on areas of geographic and electric relevance, nor adopt provisions governing how cluster subgroup areas should be formed. However, we adopt revisions to section 7.4 of the *pro forma* LGIP to permit transmission providers to use subgroups in their cluster study process if they so choose. To the extent a transmission provider chooses to use subgroups, it must include provisions in its *pro forma* LGIP in its tariff that state that it will use subgroups. We further modify section 7.4 of the *pro forma* LGIP to require that the criteria used to define subgroups be publicly posted on a publicly accessible website. We believe that publicly sharing these criteria is important to ensure adequate transparency and to safeguard against the potential for undue discrimination in the design and implementation of cluster subgroups.

364. We agree with commenters that support permitting transmission providers to study clusters in subgroups based on geographic or electrical relevance but argue that clustering projects in subgroups should not be required. We believe that there may be benefits to studying clusters in subgroups in certain circumstances, and therefore we do not want to preclude transmission providers from proposing such a process on compliance. At the same time, based on the record, we do not believe that requiring subgroups for all transmission providers is appropriate. In some instances, the administrative burden of defining and separately studying subgroups may not outweigh the benefits.

365. Consistent with our decision to not require transmission providers to conduct cluster studies on subgroups of interconnection customers, we decline to adopt provisions

governing how clusters should be formed. Rather, we believe it more appropriate to allow transmission providers to determine how to define subclusters appropriate for their regions, taking into consideration their system geography, electrical configuration, and other relevant factors.[738]

366. Regarding concerns raised by Pattern Energy and others about the use of subgroups resulting in a disproportionate allocation of network upgrade costs, we note that if a transmission provider opts to study in subgroups, it cannot change how it allocates network upgrade costs. That is, it must follow the requirement adopted in this final rule to use a proportional impact method to allocate system network upgrade costs among all interconnection customers in the cluster regardless of subgroup, as discussed further below. Because transmission providers will be using a proportional impact method to allocate system network upgrade costs, regardless of whether interconnection customers are studied in subgroups , we believe subgroups would not change an interconnection customer's potential cost allocation. An interconnection customer with an impact on a network upgrade would be allocated its portion of the cost of that network upgrade regardless of whether its request was studied in a subgroup with another interconnection customer allocated a different portion of that network upgrade.

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[738] Clean Energy Associations Initial Comments at 20; ClearPath Initial Comments at 8; EEI Initial Comments at 5; Eversource Initial Comments at 13-14; LADWP Initial Comments at 3; Longroad Energy Initial Comments at 10; MISO Initial Comments at 41-42; New York State Department Initial Comments at 5-6; PacifiCorp Initial Comments at 18; Pattern Energy Initial Comments at 15; PPL Initial Comments at 10; Shell Initial Comments, app. A at i; Tri-State Initial Comments at 11; U.S. Chamber of Commerce Initial Comments at 7.

m. Restudy

i. NOPR Proposal

367. In the NOPR, the Commission sought comment on whether to specify in the *pro forma* LGIP how cluster studies must be rerun after restudy is triggered or whether there are provisions the Commission could adopt to improve the efficacy of the restudy process, such as preventing excessive restudy by limiting the transmission provider to two restudies per month within the 150-calendar day cluster restudy period.[739]

ii. Comments

368. Eversource recommends that the Commission adopt detailed restudy rules.[740] Pine Gate suggests that the Commission provide guidance on when the need for a restudy is triggered, as even minimal changes can trigger long and costly restudies.[741] Pine Gate recommends that the Commission: (1) furnish criteria to be used by transmission providers in determining whether a restudy is required; (2) require transmission providers to limit the scope of restudies if only a local impact is anticipated; (3) require transmission providers to publish restudy criteria, determinations, and scoping as resources for interconnection customers; (4) permit interconnection customers to send engineering analyses applying the transmission provider's published criteria, which could be used by the transmission provider to help decide whether to conduct a restudy, thereby

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[739] NOPR, 179 FERC ¶ 61,194 at P 78.

[740] Eversource Initial Comments at 14.

[741] Pine Gate Initial Comments at 62-63.

reducing the transmission providers' burden; and (5) not require every cluster participant to submit additional study deposits until the transmission provider determines the need for and scope of any restudy and affected cluster participants are notified. Pattern Energy believes that transmission providers should be required to develop expedited modeling processes to evaluate whether the withdrawal of an interconnection request or other allowed modification may cause a full restudy.[742] Pattern Energy argues that such a requirement would allow interconnection customers to make better informed decisions about withdrawing or modifying interconnection requests.

369. Conversely, a number of commenters recommend that the Commission provide flexibility to transmission providers and not adopt overly prescriptive requirements specifying how cluster studies must be rerun after a restudy is triggered.[743] MISO encourages the Commission to grant maximum flexibility to transmission providers regarding the necessity of restudies and the scope of restudies as the situations that give rise to restudies are varied and unique.[744] PJM states that it finds acceptable the NOPR's proposal requiring transmission providers to specify in their tariffs how cluster studies must be rerun, but suggests the Commission avoid being overly prescriptive regarding

[742] Pattern Energy Initial Comments at 17.

[743] Bonneville Initial Comments at 9; EEI Initial Comments at 5; Idaho Power Initial Comments at 4; MISO Initial Comments at 43; NYISO Initial Comments at 12; PacifiCorp Initial Comments at 19; PJM Initial Comments at 22-23; Xcel Initial Comments at 24.

[744] MISO Initial Comments at 43.

restudies.[745] Xcel recommends that the Commission not propose additional prescriptive requirements on how restudies must be performed, but suggests that if there are multiple clusters impacted, where each cluster only has "ready" projects, the transmission provider may combine the clusters into a single cluster for a single restudy instead of restudying multiple clusters.[746]

370. Some commenters support limiting the number of restudies a transmission provider may perform within a restudy period.[747] Ameren states that limiting the number of restudies to two within the 150-day cluster restudy period seems reasonable, given the size of the many interconnection queues and the reported uncertainty of interconnection customers in the queue.[748] Ohio Commission Consumer Advocate concurs that conducting a single cluster study and cluster restudy annually may reduce the risk of cascading restudies occurring if an interconnection customer withdraws from the interconnection queue.[749]

371. A few commenters argue that the Commission should address the lack of any limit on restudy requests, stating that this issue is a known shortcoming that results in

[745] PJM Initial Comments at 22-23.

[746] Xcel Initial Comments at 24.

[747] Ameren Initial Comments at 8; Clean Energy Associations Initial Comments at 42; Cypress Creek Initial Comments at 18; Ohio Commission Consumer Advocate Initial Comments at 8; Southern Initial Comments at 24.

[748] Ameren Initial Comments at 8.

[749] Ohio Commission Consumer Advocate Initial Comments at 8.

essentially unlimited time and resource obligations for interconnection customers.[750] Southern expresses concern that the proposed *pro forma* LGIP language allows for multiple restudies, which would interfere with a one-year timeline maximum.[751]

372. A number of commenters do not support a set limit on the number of restudies a transmission provider may perform.[752] Bonneville asserts that efforts to prevent excessive restudies (e.g., limit of two per month) could be overly prescriptive.[753] Bonneville argues that transmission providers should be afforded the flexibility to determine and publish the timing of any restudy, and limits thereto, on their OASIS sites to help to facilitate transparency and ensure timelines are attainable. NextEra states that experience has shown that having a defined and limited number of restudies, such as in MISO's three-phase process, can help limit the duration of the study process.[754] However, NextEra contends that it would be too restrictive for the Commission to dictate exactly how transmission providers should limit the number of restudies, and argues that the final rule should instead require that each transmission provider propose to the

[750] Clean Energy Associations Initial Comments at 42; Cypress Creek Initial Comments at 18 (citing PJM Manual 14A at 26).

[751] Southern Initial Comments at 24.

[752] Bonneville Initial Comments at 9; MISO Initial Comments at 42, 43; NextEra Initial Comments at 15; PacifiCorp Initial Comments at 20; PJM Initial Comments at 23; Tri-State Initial Comments at 11.

[753] Bonneville Initial Comments at 9.

[754] NextEra Initial Comments at 15.

Commission on compliance what rules or processes it will use to ensure there is not an undefined and unpredictable number of restudies, e.g., whether it will have a fixed number of scheduled restudies or some other method to limit the number of restudies and associated potential delays. PacifiCorp notes that, because restudies are typically triggered through a withdrawal or modification of an interconnection request, the transmission provider is responding to changes, typically outside of its control, that warrant a restudy and undertaking efforts to complete the restudy as efficiently as possible.[755]

373. Idaho Power requests clarification surrounding the single cluster and cluster restudy process and the suggested limitation of allowing only two restudies per month within the 150-day cluster restudy period.[756] Idaho Power states, for example, an entity may have three cluster areas requiring three cluster studies, and withdrawals from those studies may require more than two simultaneous cluster restudies in the same month to prevent delay of any one cluster restudy.

iii. Commission Determination

374. We decline to modify the *pro forma* LGIP to specify how a transmission provider conducts cluster restudies and when it must conduct a cluster restudy. We find persuasive the arguments of several commenters that the Commission allow transmission providers flexibility on how and whether to conduct a restudy and the scope and

[755] PacifiCorp Initial Comments at 19.

[756] Idaho Power Initial Comments at 4.

frequency of any restudies. The transmission provider is best positioned to determine when and how to conduct a restudy, including the scope and frequency of restudies, because it determines the need for the restudies to maintain the reliability of the transmission system.[757] We agree with commenters like MISO and Xcel that different events can trigger restudies, and transmission providers are in the best position to determine whether an event warrants a restudy, and if so, what the scope of that restudy should be (for example, whether a new study is required, or whether only a modification as to certain model data and a reanalysis is required).[758]

375. As to frequency of restudies, we also agree with PacifiCorp that because restudies are typically triggered through a withdrawal of an interconnection request, the transmission provider is responding to changes, typically outside of its control, that warrant a restudy, and thus limiting the number of restudies could hinder the ability of a transmission provider to undertake efforts to complete a restudy as efficiently as possible.[759] Because we are not modifying the *pro forma* LGIP to specify how cluster studies must be rerun after restudy is triggered, we will also not limit the transmission provider to two restudies per month within the 150-calendar day cluster restudy period. We agree with commenters like Bonneville, NextEra, and PacifiCorp that it would be too

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[757] National Glossary of Terms Used in NERC Reliability Standards, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[758] MISO Initial Comments at 43; Xcel Initial Comments at 24.

[759] PacifiCorp Initial Comments at 19.

restrictive for the Commission to dictate exactly how transmission providers should limit the number of restudies.[760]

376. Regarding Idaho Power's request for clarification on the suggested limitation of allowing only two restudies per month within the 150-calendar day cluster restudy period,[761] because we are not adopting a limit of two restudies per month within the restudy period, Idaho Power's clarification request is moot.

n. Exceptions to the Cluster Study Process

i. NOPR Proposal

377. In the NOPR, the Commission sought comment on whether there should be an option in the *pro forma* LGIP for transmission providers to process some interconnection requests outside of the annual cluster study process, and if so, in what circumstances and on what time frame (for completion of the study), and on what priority compared to any active clusters.[762]

ii. Comments

378. Several parties generally support an option in the *pro forma* LGIP for some interconnection requests to be processed outside of the annual cluster study process,[763]

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[760] *Id.*; Bonneville Initial Comments at 9; NextEra Initial Comments at 15.

[761] Idaho Power Initial Comments at 4.

[762] NOPR, 179 FERC ¶ 61,194 at P 79.

[763] AES Initial Comments at 10; Fervo Energy Initial Comments at 3; Ørsted Initial Comments at 9; Tri-State Initial Comments at 11.

with some commenters supporting such an option only under specific circumstances.[764] For example, Ørsted argues that such an option could be beneficial in the case of a stand alone network upgrade built to serve a single interconnection customer that will not impact the cluster.[765] Some commenters suggest establishing a separate process outside of the cluster study process to expedite certain interconnection requests.[766] Several commenters contend that an option to study interconnection requests outside of clusters would be particularly beneficial as more renewable generating facilities are added to the resource mix.[767] Two commenters support exceptions for replacement resources specifically.[768] A few commenters argue that the Commission should allow transmission providers to separately or individually study certain interconnection requests that are not geographically or electrically relevant to other interconnection requests in the interconnection queue.[769]

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[764] AEP Initial Comments at 19, 42; APPA-LPPC Initial Comments at 15; Clean Energy Associations Initial Comments at 21; CREA and NewSun Initial Comments at 49; Energy Keepers Initial Comments at 4-5; Eversource Initial Comments at 14; Iowa Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7; UMPA Initial Comments at 3-4; Xcel Initial Comments at 24.

[765] Ørsted Initial Comments at 9.

[766] Clean Energy Associations Initial Comments at 21; Iowa Commission Initial Comments at 4; Navajo Utility Initial Comments at 13; UMPA Initial Comments at 4.

[767] AEP Initial Comments at 19-20; Clean Energy Associations Initial Comments at 21; ENGIE Reply Comments at 2; Iowa Commission Initial Comments at 4.

[768] AEP Initial Comments at 19; Clean Energy Associations Initial Comments at 21.

[769] Energy Keepers Initial Comments at 4-5; Eversource Initial Comments at 14.

379. Additionally, APPA-LPPC request that the Commission recognize that there are transmission providers, principally in rural communities or where the transmission system provides limited opportunities for advantageous interconnections, where there are too few interconnection requests to justify a cluster study approach.[770] In these cases, APPA-LPPC recommend that the Commission provide for a self-executing "opt out," permitting the transmission providers to continue to study interconnection requests on a serial basis.

380. Northwest and Intermountain recommend a limited exception to the cluster study process requirement to allow existing interconnection customers seeking to make changes to their proposed generating facilities to be processed outside of the cluster study process where the proposed change had no demonstrable incremental impact on the transmission system.[771]

381. Xcel argues that proposed generating facilities needed to serve load should be allowed to be processed outside of the annual cluster study process.[772] AEP argues that transmission providers with a reserve margin obligation must have the ability to prioritize the interconnection of needed capacity in the interconnection process.[773]

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[770] APPA-LPPC Initial Comments at 14-15.

[771] Northwest and Intermountain Initial Comments at 7-8.

[772] Xcel Initial Comments at 24.

[773] AEP Initial Comments at 42.

382. Iowa Commission argues that state commissions should have the ability to require studies outside of annual cluster studies, which would help increase the availability of needed generation for resource adequacy and maintain local reliability needs, particularly as large intermittent generating facilities are interconnecting to the system at a rapid pace.[774] Iowa Commission explains that such studies could potentially address increased transmission system stability and also minimize future transmission costs because of the "transient nature" of some load and resource changes.

383. Similarly, UMPA contends that the Commission should require a process outside of the annual cluster study process to expedite interconnection requests that are beyond the exploration phase and ready for development.[775] UMPA explains that some load serving entities search for potential resources to meet their integrated resource plan based on a request for proposal or certain competitive criteria, but are then confronted with a choice among proposed generating facilities that meet the criteria but are lower in the interconnection queue, or proposed generating facilities that do not satisfy the criteria, but are higher in the interconnection queue. Therefore, UMPA argues that it would be helpful to a load serving entity with a development-ready generating facility to be able to enter into a parallel process outside of the annual cluster study process in order to expedite an interconnection request.

[774] Iowa Commission Initial Comments at 4.

[775] UMPA Initial Comments at 3-4.

384. AEP also suggests that RTOs/ISOs that have consolidated their small and large generator interconnection procedures into a single generator interconnection procedure should be permitted to propose that all or some smaller-sized generating facilities, such as 20 MW or smaller generating facilities, would be "too small" to need to be included in the cluster.[776]

385. Other commenters believe that any exceptions to the cluster study process requirement should be very limited.[777] NRECA asserts that if the final rule provides for any interconnection requests to be processed outside the annual cluster study process, it should be limited to a narrow category of interconnection requests, such as emergency replacements of failed equipment driven by near-term reliability needs.[778] MISO asserts that there should be very limited exceptions, explaining that it has limited its non-queue interconnection requests to those that are associated with existing generating facilities that do not seek to add new or additional interconnection service, or small interconnection requests.[779] Outside of those limited exceptions, MISO states that it does

[776] AEP Initial Comments at 19.

[777] ENGIE Initial Comments at 3; MISO Initial Comments at 44; NRECA Initial Comments at 19-20.

[778] NRECA Initial Comments at 20.

[779] MISO Initial Comments at 44. MISO states that these limited exceptions are Surplus Interconnection Requests (MISO, FERC Electric Tariff, attach. X, § 3.2.3 (158.0.0)), a request for Generating Facility Replacement (MISO, FERC Electric Tariff, attach. X, section 3.7 (158.0.0)), and Fast Track Processing that is available to Small Generating Facilities under 5 MW (MISO, FERC Electric Tariff, attach. X, art. 14 (158.0.0)). *Id*. n.100.

not support processing any other interconnection requests outside of the interconnection queue.[780]

386. ENGIE recommends that exceptions be limited to requests that "need[] to be studied outside of the cluster process, e.g., transmission planning and state or public policy issues."[781] ENGIE states that it is possible that there may be other exceptions made in emergency situations, in which case, the granting of exceptions should be very limited in scope, subject to transparent criteria, and the rationale made publicly available. ENGIE further recommends that every interconnection request, including emergency requests, enter through the cluster request window, but that an emergency request be accelerated if it meets the pre-determined and publicly available requirements.

387. A number of commenters oppose an option to process interconnection requests outside of the annual cluster study process.[782] A few parties argue that maintaining an option to process interconnection requests outside of the annual cluster study process would likely create an administrative burden for transmission providers without a clear benefit.[783] Some commenters assert that processing certain interconnection requests

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[780] *Id.* at 44.

[781] ENGIE Initial Comments at 3.

[782] Bonneville Initial Comments at 9; Enel Initial Comments at 19; PacifiCorp Initial Comments at 21; PJM Initial Comments at 23; PPL Initial Comments at 12.

[783] Enel Initial Comments at 19; PacifiCorp Initial Comments at 21; PJM Initial Comments at 23.

outside of the interconnection queue could increase the time needed to complete the cluster studies or could increase restudies.[784]

388. Some commenters express concern that such an option could become overly used or abused.[785] Enel asserts that if interconnection requests could be accepted for processing outside the annual cluster study process, especially on an individual basis, there would be a high degree of interest because this would allow interconnection customers to avoid being allocated the costs of regional upgrades that result from many cluster studies.[786] Bonneville asserts that permitting an interconnection request to be processed outside of the annual cluster study process would create a "perverse incentive" for some interconnection customers to forgo the cluster study process to avoid cluster study requirements.[787]

389. OMS states that it has considered the benefits of some sort of a "fast-lane process" for resources that are more "certain," like those that have received all necessary permits and regulatory approvals.[788] OMS states that use of such a mechanism may be important or necessary in the future to address reliability concerns, but OMS explains that it is

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[784] Bonneville Initial Comments at 9; Enel Initial Comments at 19; NRECA Initial Comments at 20.

[785] Bonneville Initial Comments at 9-10; Enel Initial Comments at 19; MISO Initial Comments at 44; NRECA Initial Comments at 20.

[786] Enel Initial Comments at 19.

[787] Bonneville Initial Comments at 9-10.

[788] OMS Initial Comments at 8.

neutral on the proposal because bypassing the interconnection queue invites a myriad of potential unintended consequences that might not outweigh the value OMS otherwise envisions in this type of mechanism.

390. PacifiCorp states that the Commission's proposal on this topic is not clear.[789] PacifiCorp states that, if the NOPR refers to an interconnection customer's ability to request surplus or provisional interconnection service or an informational interconnection study, PacifiCorp supports maintaining these options. However, PacifiCorp requests the Commission clarify that requests for such service will be evaluated in the order that completed interconnection requests are received. PacifiCorp states that it does not currently support expanding non-cluster service and study offerings.

391. Regarding under what time frame and at what priority interconnection requests should be studied outside of the cluster study process, as compared to any active clusters, Fervo Energy recommends a 270-day time frame for completion of the study with secondary priority to the active cluster studies.[790]

iii. Commission Determination

392. We decline to include an additional option in the *pro forma* LGIP for transmission providers to process some interconnection requests outside the annual cluster study process adopted in this final rule. We find that establishing in the *pro forma* LGIP a separate interconnection process outside the cluster study process could detract from

[789] PacifiCorp Initial Comments at 21.

[790] Fervo Energy Initial Comments at 3.

transmission providers' efforts to efficiently process cluster studies—a point persuasively argued by commenters.[791] A separate set of interconnection studies outside of the cluster study process could cause transmission providers to divert resources away from cluster studies and cluster restudies. Such diversion could hinder the transmission provider from meeting the cluster study and cluster restudy deadlines adopted in this final rule, which would be insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. We also find that such an option in the *pro forma* LGIP would be too open-ended, as it would leave a significant amount of discretion to the transmission provider to create new study processes for processing any types of interconnection requests it chooses outside the cluster study process and could therefore result in a separate but unduly discriminatory interconnection process. We further find that establishing such an open-ended option in the *pro forma* LGIP could create an incentive for some interconnection customers to forgo the cluster study process, which could increase the time and resources needed for transmission providers to complete the cluster studies or could increase restudies.[792]

393. A number of commenters see benefits to establishing an option in the *pro forma* LGIP for particular types of interconnection requests to be processed outside of the annual cluster study process, such as for generator replacement, projects ready for

[791] Bonneville Initial Comments at 9; Enel Initial Comments at 19; NRECA Initial Comments at 20; PacifiCorp Initial Comments at 21; PJM Initial Comments at 23.

[792] Bonneville Initial Comments at 9-10; Enel Initial Comments at 19; MISO Initial Comments at 44; NRECA Initial Comments at 20; PJM Initial Comments at 23.

development, emergency replacements, for certain special circumstances, or for transmission providers who have too few interconnection requests to justify a cluster study approach.[793] However, we are not persuaded that establishing such processes in the *pro forma* LGIP is necessary to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. We believe that processing such one-off interconnection requests will be needed less often under the cluster study process adopted in this final rule, and therefore, any benefits that exist to processing some interconnection requests outside a transmission provider's interconnection process may be outweighed by the benefit of allowing transmission providers to conduct cluster studies efficiently without diverting resources to a separate set of studies.

394. In response to the Iowa Commission's argument that state commissions should be able to require studies outside of annual cluster studies, we similarly find that any such studies would divert a transmission provider's resources away from conducting the cluster studies and cluster restudies.

395. Regarding AEP's suggestion that those RTOs/ISOs that have consolidated their small and large generator interconnection procedures should be permitted to propose that all or some smaller-sized generating facilities would be "too small" to be included in the

[793] AEP Initial Comments at 19; APPA-LPPC Initial Comments at 14-15; Clean Energy Associations Initial Comments at 21; Energy Keepers Initial Comments at 4-5; Navajo Utility Initial Comments at 13; NRECA Initial Comments at 19-20; UMPA Initial Comments at 3-4.

cluster, we note that the Commission did not propose the cluster study process for small generating facilities subject to the *pro forma* SGIP.

396. Finally, because we are not revising the *pro forma* LGIP to add a new option for some interconnection requests to be processed outside of the annual cluster study process, we find moot those comments on the time frame and priority of interconnection requests studied outside of the cluster study process.[794] In response to PacifiCorp,[795] we clarify that requests for surplus interconnection service, or an optional interconnection study, will continue to be processed as received and outside of the cluster study process, and that this does not entail an expansion of non-cluster service and study offerings.

o. Other Comments

i. Comments

397. Some entities recommend automation or standardization of the interconnection queue process and studies.[796] NextEra states that the proposed cluster study process time frame requires significant information technology and personnel resources.[797] NextEra argues that, despite the lack of such a proposal in the NOPR, automation of the interconnection queue process and studies is likely the key to compressing

[794] Fervo Energy Initial Comments at 3; Tri-State Initial Comments at 12; Xcel Initial Comments at 24-25.

[795] PacifiCorp Initial Comments at 21.

[796] ACORE Initial Comments at 4-5; Clean Energy Associations Initial Comments at 26; NextEra Initial Comments at 13.

[797] NextEra Initial Comments at 13-14.

interconnection process timelines. NextEra encourages the Commission to convene a technical conference or other process to focus on the root causes of interconnection study delays as well as the potential to accelerate the interconnection queue process through enhanced automation.

398. Several commenters argue that the Commission should require transmission providers to provide more cost information to interconnection customers throughout the interconnection process.[798] Clean Energy Associations and SEIA argue that cluster studies should also ensure that interim cost information is made available to interconnection customers so that they can make more informed decisions earlier in the interconnection process, which will in turn lead to a more efficient interconnection process overall.[799] Clean Energy Associations argue that as part of the cluster studies provided to interconnection customers prior to their receiving facilities studies, the Commission should require transmission providers to provide interconnection customers with cost estimates for the upgrades required if they were to request ERIS or NRIS (or long-term firm transmission service), respectively—and coupled with minimum thresholds for materiality (such as distribution factor) and transparency regarding how these costs are derived (detailing the assumptions and criteria that will be used).[800] Clean

[798] ACE-NY Initial Comments at 4; Clean Energy Associations Initial Comments at 20; Enel Initial Comments at 18; SEIA Initial Comments at 8.

[799] Clean Energy Associations Initial Comments at 20; SEIA Initial Comments at 8.

[800] Clean Energy Associations Initial Comments at 27.

Energy Associations also suggest that the Commission should provide concrete direction regarding how differing service types should be studied, and what outcome an interconnection customer should receive for making the necessary transmission system improvements to obtain that interconnection service.[801] AEE similarly believes that additional reforms are needed to bring more transparency and predictability to interconnection costs, and without this transparency and predictability, interconnection customers face continued risks of unjust and unreasonable interconnection study results that derail or delay interconnection requests and cause increased costs.[802]

399. Affected Interconnection Customers state that the Commission should permit interconnection customers to use independent studies to demonstrate whether the request for limited interconnection service would result in stability, short circuit, thermal, and/or voltage issues, if the transmission provider or transmission owner is unable to complete the studies on time.[803] Affected Interconnection Customers argue that allowing interconnection customers to use any available resources to conduct these studies would enable already built interconnection facilities to flow power onto the system, as long as studies show that such interim services will not harm the system.

400. Clean Energy Associations ask that in a final rule, the Commission adopt a cost threshold (in terms of the anticipated upgrade cost relative to distribution factor) beyond

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[801] *Id.* at 29.

[802] AEE Initial Comments at 12.

[803] Affected Interconnection Customers Initial Comments at 21.

which upgrades should be evaluated in the next near-term transmission planning process. Similarly, Clean Energy Associations argue that cumulative congestion issues should also be addressed via the transmission planning process.[804]

ii. <u>Commission Determination</u>

401. We decline to adopt the remainder of the proposals advocated for in the comments regarding our requirement for transmission providers to use a cluster study process. We decline to adopt three of these proposals because they are outside the scope of the NOPR: (1) NextEra's request to require or standardize automated processing of interconnection requests;[805] (2) Clean Energy Associations' argument that the Commission should adopt a cost threshold beyond which upgrades should be evaluated in the next near-term transmission planning process;[806] and (3) Clean Energy Associations' argument that the Commission should provide concrete direction regarding how differing service types should be studied, and what outcome an interconnection customer should receive for making the necessary transmission system improvements to obtain that interconnection service.[807]

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[804] Clean Energy Associations Initial Comments at 29.

[805] NextEra Initial Comments at 14. We also decline to convene a technical conference to explore the causes of interconnection study delays and the potential to accelerate the interconnection queue process through enhanced automation. As discussed above, we have adequate record of the causes of interconnection study delays to fashion a remedy with the combination of reforms we adopt in this final rule.

[806] Clean Energy Associations Initial Comments at 29.

[807] *Id.*

402. Regarding Affected Interconnection Customers' arguments discussing the use of independent studies, we note that interconnection customers can use independent resources during the interconnection process. However, the results of independent studies will not be binding on transmission providers, as the use of studies conducted by an interconnection customer cannot ensure that the cluster study process results in a just, reasonable, and not unduly discriminatory or preferential outcome for all interconnection customers in the cluster. In addition, transmission providers must be able to conduct the necessary studies to maintain the reliability of their transmission system.

403. We will not require transmission providers to provide additional cost information to interconnection customers that is not already required to be provided pursuant to the *pro forma* LGIP, as modified by this final rule. For example, revised *pro forma* LGIP sections 3.4.5 (Customer Engagement Window) and 8.1 (Interconnection Facilities Study Agreement) require the transmission provider to provide the interconnection customer with a good faith estimate of the costs of the cluster study and the interconnection facility study, respectively. Similarly, revised *pro forma* LGIP sections 7.3 (Scope of Cluster Study) and 8.2 (Scope of Interconnection Facilities Study) require the transmission provider to provide cost estimates for interconnection facilities and network upgrades. It is unclear what other "interim cost information"[808] Clean Energy Associations want transmission providers to provide, nor the value of such information vis-à-vis the burden on transmission providers to develop it.

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[808] *Id.* at 20.

404. Clean Energy Associations argue that as part of the cluster studies provided to interconnection customers prior to receiving facilities studies, the Commission should require transmission providers to provide interconnection customers with cost estimates for the upgrades required if they were to request ERIS or NRIS. Section 3.2 of the *pro forma* LGIP provides that an interconnection customer requesting NRIS may also request that it be concurrently studied for ERIS, up to the point when the facility study agreement is executed. As the *pro forma* LGIP already provides interconnection customers the ability to have both ERIS and NRIS studied concurrently, we find Clean Energy Associations' request moot.

3. Allocation of Cluster Study Costs

a. NOPR Proposal

405. In the NOPR, the Commission proposed to require transmission providers to allocate the shared costs of cluster studies as follows: 90% of the applicable study costs allocated pro rata to interconnection customers based on requested MWs included in the applicable cluster, and 10% of the applicable study costs allocated per capita to interconnection customers based on the number of interconnection requests included in the applicable cluster.[809] The Commission preliminarily found that this allocation of the costs of cluster studies would result in just and reasonable Commission-jurisdictional rates because it appropriately recognizes that the MW size of a cluster has a dramatic impact on the cost of studying the cluster, while also recognizing that the number of

[809] NOPR, 179 FERC ¶ 61,194 at P 82.

interconnection requests included in the cluster also impacts the cost of studying the cluster, but to a lesser degree. The Commission sought comment on whether a different cost allocation approach may be appropriate or whether each transmission provider should be provided additional flexibility to propose a cost allocation approach on compliance with any final rule.[810]

b. Comments

i. Comments in Support

406. Multiple commenters support the proposal.[811] Clean Energy Buyers note that certainty and consistency in cost allocation for interconnection studies will be helpful for interconnection customers that site generating facilities in more than one region.[812] Idaho Power adds that a uniform cost allocation would prevent interconnection customers from "shopping around" for the best price for larger generating facility locations.[813] Duke Southeast Utilities note that Duke Carolinas Utilities' currently effective LGIP/LGIA contains the same 90/10 cost allocation, which it states provides a balanced and equitable

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[810] *Id.* P 83.

[811] Clean Energy Buyers Initial Comments at 8; Consumers Energy Initial Comments at 4; Cypress Creek Initial Comments at 19; Duke Southeast Utilities Initial Comments at 8-9; Enel Initial Comments at 20; Fervo Energy Initial Comments at 3; Idaho Power Initial Comments at 5; Interwest Initial Comments at 5; Public Interest Organizations Initial Comments at 31; R Street Initial Comments at 11; Tri-State Initial Comments at 3, 12.

[812] Clean Energy Buyers Initial Comments at 8-9.

[813] Idaho Power Initial Comments at 5.

study cost allocation based on the Commission's cost causation principle.[814] Duke Southeast Utilities assert that the proposed allocation aligns with study deposits that would be submitted based on varying assumptions around the number and size of interconnection requests submitted into the cluster study process.

ii. Comments in Opposition

407. Several commenters oppose the proposal. For instance, National Grid and NRECA argue that any predetermined study cost allocation method will produce results that do not comport with cost causation.[815] National Grid gives the example of a 20 MW generating facility that has unique or complex engineering features at a particular point of interconnection that may require considerably more time to conduct a study than a much larger 100 MW generating facility; in this situation, according to National Grid, the 90/10 cost allocation methodology proposed in the NOPR would not align with cost causation, a problem that would be exacerbated if the interconnection customer withdraws the interconnection request.[816] National Grid asserts that a predetermined cost allocation risks undermining competitive pressures in the interconnection process, which it states should be retained to the maximum extent possible consistent with revisions to mitigate the existing interconnection queue inefficiencies. Similarly, Xcel and NextEra argue that the size of the interconnection request does not impact the study costs by a 9:1 ratio

[814] Duke Southeast Utilities Initial Comments at 8-9.

[815] National Grid Initial Comments at 16; NRECA Initial Comments at 8.

[816] National Grid Initial Comments at 16-17.

compared to the number of interconnection requests, noting that the size of the interconnection request does not materially impact the time to add the generating facility to the model or time to design the interconnecting substation.[817] NRECA adds that the Commission has not produced data showing the fixed costs of processing an interconnection request or a precise linear correlation between generating facility size and study costs.[818] rPlus argues that the proposed 90/10 cost allocation is "unduly discriminatory toward pumped storage, and wholly disincentivizes large capacity projects."[819] rPlus argues that the assertion that the MW size of a cluster study is significantly more impactful on the cost and effort required to perform the study is incorrect. rPlus states that the number of interconnection requests and the cluster size are both burdensome for the study process, as each generating facility requires its own project management, technical review, study implementation, and deliverability assessment.[820] SDG&E and SoCal Edison agree that a 90/10 cost allocation would inappropriately burden larger generating facilities with higher study costs, as the level of effort to study an interconnection request is driven more by complexity around the point of interconnection and is not strongly correlated to the size of the generating facility.[821]

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[817] NextEra Initial Comments at 16; Xcel Initial Comments at 25.

[818] NRECA Initial Comments at 21.

[819] rPlus Initial Comments at 5.

[820] *Id.*; Hydropower Commenters Initial Comments at 27.

[821] SDG&E Initial Comments at 7; SoCal Edison Initial Comments at 15.

iii. Alternatives and Requests for Flexibility

408. Several commenters put forth alternatives to the NOPR proposal. For instance, some commenters generally contend that transmission providers should allocate study costs based on the proposed generating facility's impact on the overall study, measured by the time and resources expended on a particular generating facility within the study.[822] National Grid asserts that this process would be consistent with the current serial study approach, which directly correlates cost responsibility to cost causation.[823] AES argues that the final rule's cost allocation framework should reflect the reality that study costs are not only a function of generating facility size, but also the location of the generating facility and the degree to which that location is constrained.[824]

409. Several commenters argue that the Commission should allocate cluster study costs based solely on the number of interconnection requests in the cluster.[825] Ameren and SDG&E state that, in their experience, study costs are not based on the size of the proposed generating facilities.[826] In contrast, Fervo Energy argues against allocating study costs evenly to all interconnection customers within a cluster, asserting that it is "not at all

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[822] AES Initial Comments at 12; Clean Energy Associations Initial Comments at 23; National Grid Initial Comments at 17.

[823] National Grid Initial Comments at 17.

[824] AES Initial Comments at 12.

[825] Ameren Initial Comments at 11; SDG&E Initial Comments at 7; SoCal Edison Initial Comments at 15-16.

[826] Ameren Initial Comments at 11; SDG&E Initial Comments at 7.

clear" how this proposal is just and reasonable, as it strays away from allocating costs on a pro rata basis based on requested MWs.[827]

410. CAISO argues that the proposal appears arbitrary and capricious because the Commission does not adequately explain the basis for the 90% to 10% ratio.[828] CAISO asserts that the 10% allocation is so small as to be de minimis, yet it still increases the administrative burden to allocate the cluster study costs. CAISO argues that it would be much simpler and easier if transmission providers simply allocated all cluster study costs based on the MW capacity alone.

411. Enel argues that there are study phases where it would be more appropriate to assign study costs to individual interconnection requests, "such as the [f]acilities [s]tudy for upgrades assigned to only a single customer."[829] Enel argues that a 90/10 study cost split may disproportionately exclude very small generating facilities which still require modeling from study cost responsibility, and suggests that a minimum MW size be assumed, such as was used to set the minimum study deposit in proposed *pro forma* LGIP section 3.1.1.1.

412. Several commenters argue for a cost allocation of 50% of the study costs based on requested MW and 50% based on the number of interconnection requests in the cluster.[830]

[827] Fervo Energy Reply Comments at 4.

[828] CAISO Initial Comments at 12.

[829] Enel Initial Comments at 20.

[830] Hydropower Commenters Initial Comments at 26-27; NextEra Initial Comments at 16; Pattern Energy Initial Comments at 18-19; rPlus Initial Comments at 5;

NextEra states that, based on its experience, it takes comparable time and effort to study a small proposed generating facility as a large one.[831] NextEra and SoCal Edison argue that allocating study costs based mostly on the MW size would likely cause some cross-subsidies from interconnection customers submitting large proposed generating facilities to those submitting smaller ones.[832] SEIA notes that the MW size of the cluster may be artificially inflated when certain interconnection customers submit multiple exploratory requests, and recommends a 50/50 cost allocation to deter such requests.[833] SEIA argues that, similar to CAISO's study cost allocation, the Commission should structure the cost allocation so that interconnection customers with multiple interconnection requests are responsible for a greater share of the study costs.[834]

413. Clean Energy Associations add that cluster studies should be conducted in subgroups based on electrical relevance, and that study costs related to each subgroup should be tracked independently and allocated only among those interconnection customers within that subgroup.[835]

SEIA Initial Comments at 9-10.

[831] NextEra Initial Comments at 16.

[832] *Id.*; SoCal Edison Initial Comments at 15-16.

[833] SEIA Initial Comments at 10.

[834] *Id.* (citing *Cal. Indep. Sys. Operator, Inc.*, 140 FERC ¶ 61,070, at P 4 (2012)).

[835] Clean Energy Associations Initial Comments at 23.

414. Multiple commenters argue that the Commission should not impose a specific cluster study cost allocation, but instead allow transmission providers flexibility in proposing their own cost allocation methods.[836] For example, APPA-LPPC argue that the use of a "one-size-fits-all" approach may result in unreasonable results in certain circumstances.[837] APPA-LPPC assert that weighting the allocation of cluster study costs based on MWs may unfairly burden interconnection customers proposing large generating facilities in regions where a cluster is likely to include a large number of relatively small proposed generating facilities and a small number of large proposed generating facilities because study costs do not necessarily track linearly with generating facility size.

415. Several commenters argue that RTOs/ISOs should be able to retain their existing cluster study cost allocations, where applicable, because those cost allocations accomplish the purpose of the Commission's proposal to equitably allocate study costs among interconnection customers.[838]

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[836] AES Initial Comments at 12; Ameren Initial Comments at 11; APPA-LPPC Initial Comments at 3; Bonneville Initial Comments at 10; Clean Energy Associations Initial Comments at 24; Dominion Initial Comments at 19; Indicated PJM TOs Initial Comments at 18-19; ISO-NE Initial Comments at 25; MISO Initial Comments at 45; National Grid Initial Comments at 16; NextEra Initial Comments at 16-17; NRECA Initial Comments at 8; NYISO Initial Comments at 13; Omaha Public Power Initial Comments at 5; Ørsted Initial Comments at 9; Pattern Energy Initial Comments at 19; PPL Initial Comments at 12; R Street Initial Comments at 11; SEIA Initial Comments at 10; Xcel Initial Comments at 25.

[837] APPA-LPPC Initial Comments at 16.

[838] Dominion Initial Comments at 19; Indicated PJM TOs Initial Comments at 18-19; ISO-NE Initial Comments at 25; MISO Initial Comments at 45; NYISO Initial

c. Commission Determination

416. We adopt the NOPR proposal, with modification, to revise section 13.3 (Obligation for Study Costs) of the *pro forma* LGIP to allow each transmission provider to propose its own study cost allocation ratio for allocating the shared costs of cluster studies between a per capita basis and pro rata by MW, provided that: between 10% and 50% of study costs must be allocated on a per capita basis, with the remainder (between 90% and 50%) allocated pro rata by MW. Under this revised provision, a transmission provider may propose to retain its existing study cost allocation ratio if it falls within this range and meets the requirements of this final rule.

417. We are persuaded by comments arguing that it is appropriate to allow transmission providers a degree of flexibility in proposing on compliance the method for allocating study costs in their tariff to adapt to their specific regional circumstances and help avoid unreasonable outcomes. Some commenters assert that the NOPR-proposed 90%-10% allocation could in some instances unduly burden larger generating facilities, such as when a cluster includes a large number of interconnection requests representing relatively small generating facilities and a small number of large generating facilities.[839] Conversely, other commenters caution that straying too far from the NOPR proposal for a

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Comments at 14; Omaha Public Power Initial Comments at 5; PJM Initial Comments at 35; SPP Initial Comments at 7. In response, Fervo Energy cautions against permitting transmission providers too much flexibility, arguing that this opens the door for undue discrimination against interconnection customers. Fervo Energy Reply Comments at 4.

[839] APPA-LPPC Initial Comments at 16.

90%-10% allocation could disproportionately burden smaller generating facilities, given the role that size may play in determining study costs.[840] Accordingly, we believe that granting transmission providers the flexibility to propose in their tariff the study cost allocation appropriate to their region, within the limits detailed above, strikes a better balance than the NOPR proposal.

418. The revised study cost allocation requirements that we adopt in this final rule recognize that cluster study costs are impacted by both the number of interconnection requests in a cluster and the size of the proposed generating facilities in each cluster. We find that requiring transmission providers to allocate between 10% and 50% of cluster study costs on a per capita basis is just and reasonable because it ensures that interconnection customers that propose smaller generating facilities or submit multiple interconnection requests to explore different interconnection scenarios for a single proposed generator adequately contribute to study costs, particularly given that some study costs are incurred independent of the MW size of a specific proposed generating facility in a cluster.[841] Further, we agree with commenters that observe that not all study costs track linearly with generating facility size because there are other factors, such as the point of interconnection selected, that can lead to increasingly complex studies and

[840] Fervo Energy Reply Comments at 4-5.

[841] SDG&E Initial Comments at 7; SoCal Edison Initial Comments at 15.

correspondingly higher study costs.[842] We believe that the per capita component of the study cost allocation requirements addresses this fact. Requiring a per capita component also ensures that an interconnection customer that proposes a large generating facility in a cluster of many smaller generating facilities will not bear a disproportionate amount of the study costs. We likewise find that requiring transmission providers to allocate between 50% and 90% of study costs on a pro rata by MW basis prevents a disproportionate amount of study costs from being allocated to interconnection customers that propose smaller generating facilities in the cluster. The pro rata by MW component reflects the fact that, to a significant extent, study costs correlate to the total MW size of the cluster. In general, even if the number of interconnection requests in each cluster remains constant, we expect that a cluster of 10,000 MW will be significantly more costly to study than a cluster of 100 MW.[843] Accordingly, requiring that a substantial share of study costs is allocated based on each generating facility's contribution to the total MW size of the cluster study ensures consistency with cost causation principles.

419. We disagree with CAISO that the Commission should require the allocation of all cluster study costs based on the MW capacity because allocating 10% of study costs on a per capita basis is *de minimis* and not worth the administrative burden. First, this final rule now allows transmission providers to allocate up to 50% of costs on a per capita

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[842] AES Initial Comments at 12; APPA-LPPC Initial Comments at 16; NRECA Initial Comments at 21.

[843] Fervo Initial Comments at 4.

basis. Even if a transmission provider chooses to allocate only 10% of study costs on a per capita basis, as explained above, we believe that this is an important component that is needed to ensure that study costs are allocated in a manner that is at least roughly commensurate with estimated benefits (i.e., consistent with cost causation). We are unpersuaded that the administrative burden associated with allocating a potentially small fraction of the study costs among interconnection customers in a cluster outweighs the benefits, particularly given that nothing in the record demonstrates that those administrative costs are significant.

420. In response to commenters' arguments in favor of a uniform study cost allocation method across regions, we find that the benefits of allowing transmission providers flexibility to tailor their study cost allocation to the specific circumstances of their region outweigh the benefits of uniformity cited by commenters, such as consistency and preventing "shopping around." We believe that the guardrails that we provide in this final rule will ensure just, reasonable, and not unduly discriminatory or preferential rates while at the same time addressing concerns with the different characteristics of regions. We urge stakeholders to engage with transmission providers as part of the compliance process as the transmission providers develop their proposed study cost allocations.

421. In response to National Grid, AES, and Clean Energy Associations' comments arguing that costs should be allocated based on individual calculations of the actual time and resources expended on a particular interconnection request, we find that such individual calculations would not only increase the administrative burden on transmission providers, but also would offer little benefit given the cluster study context, which

requires transmission providers to evaluate multiple interconnection requests simultaneously.[844] We are also unconvinced that a transmission provider could accurately perform such calculations because, as explained above, some study costs are unrelated to an individual interconnection request and are instead incurred as a matter of course as part of studying a cluster of interconnection requests.

4. Allocation of Cluster Network Upgrade Costs

a. NOPR Proposal

422. In the NOPR, the Commission proposed to require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method.[845] The Commission also proposed to add the defined term proportional impact method to the *pro forma* LGIP and require transmission providers to revise their LGIPs to include the specific technical parameters and thresholds of their method for cost allocation. The Commission also proposed to require transmission providers to allocate the costs of transmission provider's interconnection facilities equally among all interconnection customers sharing use of the transmission provider's interconnection facilities. The Commission sought comment on: (1) whether there are specific types of analyses that the Commission should require transmission providers to use to determine the proportional impact attributed to an interconnection request,

[844] AES Initial Comments at 12; Clean Energy Associations Initial Comments at 23; National Grid Initial Comments at 17.

[845] NOPR, 179 FERC ¶ 61,194 at P 88.

including the benefits and drawbacks of any proposed approach; (2) whether there are specific types of analyses that the Commission should prohibit because they are known to be inaccurate, provide undue discretion to the transmission provider, or could otherwise be problematic; (3) whether alternative methods to allocate the costs of network upgrades within a cluster, such as the proportional capacity method, can be sufficiently accurate in certain instances, in a manner consistent with or superior to the proposed method; and (4) whether there are some circumstances where the proportional capacity method would not be appropriate, such as circumstances where there may be potential for discriminatory treatment.[846]

b. Comments

i. General Comments

423. Several commenters support the proposal.[847] These commenters state that the proposed proportional impact cost allocation method is widely used, both by RTOs/ISOs and non-RTO/ISO transmission providers,[848] and ensures that each interconnection

[846] *Id.* P 89.

[847] ACORE Initial Comments at 8; Ameren Initial Comments at 12; Avangrid Initial Comments at 31; Cypress Creek Initial Comments at 19; Eversource Initial Comments at 15; Fervo Energy Initial Comments at 3; Interwest Initial Comments at 16-17; Invenergy Initial Comments at 21; NEPOOL Initial Comments at 15; New Jersey Commission Initial Comments at 15; Northwest and Intermountain Initial Comments at 8; NYTOs Initial Comments at 16; Omaha Public Power Initial Comments at 5; Pennsylvania Commission Initial Comments at 8-9.

[848] For example, several transmission providers support the Commission's proposal, and state that they already use a proportional impact method or distribution factor analysis. CAISO Initial Comments at 13; ISO-NE Initial Comments at 25; MISO Initial Comments at 46-47; NYISO Initial Comments at 14; PJM Initial Comments at 36;

customer contributes to the cost of network upgrades in proportion to its impact on the transmission system.[849] These commenters assert that other options (such as a proportional capacity or a pro rata allocation per interconnection request) would be more likely to shift a disproportionate share of network upgrade costs to smaller generating facilities, which may have less impact on the transmission system.[850] Bonneville and Interwest argue that the proportional impact method could also reduce the incentive for interconnection customers to submit multiple speculative requests and reduce the amount of cascading withdrawals and restudies.[851] ELCON contends that, should any one proposed generating facility in the cluster have an outsized impact on the transmission system compared to other proposed generating facilities in the cluster, those other proposed generating facilities should be protected from exorbitant network upgrade costs

SoCal Edison Initial Comments at 16; Tri-State Initial Comments at 12.

[849] ACORE Initial Comments at 8; Ameren Initial Comments at 12; Avangrid Initial Comments at 31; Cypress Creek Initial Comments at 19; Eversource Initial Comments at 15; Fervo Energy Initial Comments at 3; Interwest Initial Comments at 16-17; Invenergy Initial Comments at 21; NEPOOL Initial Comments at 15; New Jersey Commission Initial Comments at 15; Northwest and Intermountain Initial Comments at 8; NYTOs Initial Comments at 16; Omaha Public Power Initial Comments at 5; Pennsylvania Commission Initial Comments at 8-9.

[850] ACORE Initial Comments at 8; Ameren Initial Comments at 12; Avangrid Initial Comments at 31; Cypress Creek Initial Comments at 19, Eversource Initial Comments at 15; Fervo Energy Initial Comments at 3, Interwest Initial Comments at 16-17; Invenergy Initial Comments at 21; NEPOOL Initial Comments at 15; New Jersey Commission Initial Comments at 15; Northwest and Intermountain Initial Comments at 8; NYTOs Initial Comments at 16; Omaha Public Power Initial Comments at 5; Pennsylvania Commission Initial Comments at 8-9.

[851] Bonneville Initial Comments at 10; Interwest Initial Comments at 17.

to accommodate a proposed generating facility that may not be suitably located.[852] CAISO adds that it has used distribution factor analysis without controversy.[853]

424. NRECA states that it interprets this proposal to implement—and not modify, weaken, or permit deviations from—the Commission's established policy that transmission costs, including network upgrade costs, must be allocated in a manner at least reasonably commensurate with estimated benefits.[854] NRECA states that, based on that interpretation of the NOPR's proposal, NRECA believes this method is fair to both interconnection customers and transmission providers and helps ensure that the costs to implement an interconnection request are allocated reasonably commensurate with cost causation and expected benefits. NRECA states that the proportional impact method is also reasonably transparent and relatively easy for transmission providers to implement, explain, and defend.

425. In response to the Commission's request for comment on whether there are circumstances in which the proportional capacity method would be appropriate, some commenters argue that the proportional capacity method is never appropriate and should be expressly prohibited for clusters.[855] MISO argues that network upgrade cost allocation

[852] ELCON Initial Comments at 9.

[853] CAISO Initial Comments at 13.

[854] NRECA Initial Comments at 22.

[855] Longroad Energy Initial Comments at 9; MISO Initial Comments at 45-46; NRECA Initial Comments at 22; Pennsylvania Commission Initial Comments at 9.

methods that only consider installed capacity without considering the network topology do not consider the full picture of what an interconnection customer's responsibility for the network upgrade costs should be.[856] Pennsylvania Commission asserts that large generating facilities would continue to bear high network upgrade costs and would have an incentive to interconnect wisely, while small generating facilities, which are becoming the norm in interconnection queues, would not.[857] Pennsylvania Commission contends that this would create a subsidy whereby large generating facilities pay a share of unnecessary network upgrade costs caused by poor siting of smaller generating facilities.[858] Longroad Energy illustrates this point by noting that one of its generating facilities was recently allocated nearly $10 million under the proportional capacity method based solely on the generating facility's size, despite the fact that relevant interconnection studies firmly established that its generating facility, while large, actually reduced the identified overload.[859]

426. NV Energy urges the Commission to reconsider the application of pro rata allocation of network upgrade costs over using the proportional impact method.[860] NV Energy contends that the proportional impact method could negatively impact

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[856] MISO Initial Comments at 45-46.

[857] Pennsylvania Commission Initial Comments at 9.

[858] *Id.*; *see also* NRECA Initial Comments at 22.

[859] Longroad Energy Initial Comments at 9.

[860] NV Energy Initial Comments at 12.

interconnection customers due to the time and risk of reallocations required by restudies.[861] NV Energy argues that assigned network upgrade costs could change dramatically if a cluster participant withdraws from the interconnection queue and requires a restudy, potentially resulting in each participant's cost allocation changing.[862] NV Energy asserts that in addition to disintegrating cost reassurance for the interconnection customer, performing studies using the proportional impact method defeats the purpose of completing cluster studies where each interconnection customer in the cluster has the same interconnection queue position and that this method will require the transmission provider to review each interconnection request within the cluster individually to assign the proportional impact.

427. NV Energy contends that using the proportional impact method to allocate the costs of network upgrades resulting from cluster studies will be burdensome in application because of the volume of interconnection requests being studied and the large number of network upgrades identified in each study.[863] NV Energy states that, under a proportional capacity method, when an interconnection customer withdraws and the same network upgrades are deemed necessary, the transmission provider could simply reallocate a pro rata share to the remaining interconnection customers and expedite the study; however, in the case of the proportional impact method, the transmission provider

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[861] *Id.*; PacifiCorp Reply Comments at 3.

[862] NV Energy Initial Comments at 12.

[863] *Id.*

would need to complete a full restudy to review each generating facility's impact on the system.

428. According to NV Energy, this issue is further exacerbated when a network upgrade becomes a shared network upgrade with another cluster and the proportional impact is expanded to include additional interconnection customers.[864] NV Energy states that, not only would the restudy be required for the lower-queued cluster based on the withdrawal, but also the concurrently queued cluster to modify the network upgrade cost allocation. NV Energy also argues that, without a consistent proportional impact cost allocation amongst transmission providers, there is risk that this could lead to disputes at the Commission from interconnection customers, which would lead to increased costs and delays.

429. PacifiCorp strongly opposes the proportional impact method to allocate network upgrade costs.[865] PacifiCorp argues that the Commission has not made a transmission provider-specific finding that the proportional capacity method, approved for PacifiCorp by the Commission in May 2020,[866] is no longer just and reasonable. PacifiCorp contends that transmission providers should be permitted to use proportional capacity-based network upgrade cost allocation methods.[867] PacifiCorp claims that the

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[864] *Id.* at 13.

[865] PacifiCorp Initial Comments at 23.

[866] *PacifiCorp*, 171 FERC ¶ 61,112 (2020).

[867] PacifiCorp Initial Comments at 22, 26.

proportional capacity method it uses is informed by three additional mechanisms within the cluster study process, all of which work in tandem to ensure that costs are appropriately allocated: (1) the use of electrically or geographically relevant subregions; (2) iterative studies that consider ERIS network upgrades prior to NRIS requests; and (3) a floor of 1% of total MW within a cluster, under which interconnection requests will be deemed not to contribute to the network upgrades identified in the cluster study.[868]

430. PacifiCorp states that the proportional capacity method also assists it in completing cluster studies and restudies on a timely basis, and minimizes disputes.[869] PacifiCorp argues that, in sharp contrast, the proportional impact method involves a complex analysis that, in addition to being excessively time consuming, will result in disputes, both of which will put substantial pressure on PacifiCorp's ability to meet study deadlines.[870] Therefore, according to PacifiCorp, requiring use of the proportional impact method will be counterproductive to the Commission's intent of making processing of interconnection requests more efficient.

431. PacifiCorp explains that the degree of contribution to a needed network upgrade can be very difficult to determine depending on the size, number of interconnection requests, and location of proposed generating facilities in a cluster.[871] PacifiCorp adds

[868] *Id.* at 23-24.

[869] *Id.*; PacifiCorp Reply Comments at 2.

[870] PacifiCorp Initial Comments at 24-25.

[871] *Id.* at 25.

that a proportional impact method analysis is complicated further by the fact that all interconnection requests within a single cluster are considered equally queued. In addition, PacifiCorp argues that, given the size of its multi-state system and the thousands of MWs of interconnection requests entering the cluster study process each year,[872] it is simply not possible to both perform a proportional impact method analysis on each interconnection request and complete the cluster study process within 150 calendar days.[873]

ii. Comments on Specific Proposal

(a) Specificity Regarding Technical Parameters and Thresholds

432. Several commenters state that, if the Commission adopts its proposal for each transmission provider to revise its tariff to include its specific technical parameters and thresholds for the proportional impact method for network upgrade cost allocation, the Commission should at least consider guidance or principles for those technical parameters and thresholds.[874] The same commenters ask that the Commission also require sufficient specificity to provide transparency and certainty for potential interconnection customers and to avoid disputes over cost allocation.

[872] PacifiCorp states that during the most recent cluster study, which commenced in May 2022, PacifiCorp received around 40 GW-worth of interconnection requests, which is more than three times PacifiCorp's peak system load.

[873] PacifiCorp Initial Comments at 25.

[874] Clean Energy Buyers Initial Comments at 9; Cypress Creek Initial Comments at 19; Invenergy Initial Comments at 21.

433. EPSA and Vistra argue that the Commission should provide an opportunity for comments prior to moving to a final rule with more detailed parameters.[875] Vistra contends that without such an opportunity, the Commission will have not provided sufficient notice.[876] Vistra argues that adopting a final rule that contains only the very high-level requirement to allocate costs based on proportional impact method simply defers the Commission's determination on important implementation details to litigation over the individual compliance filings that will be submitted. Without sufficient detail, Vistra continues, the Commission will arguably need to accept any set of technical details as in compliance with the requirement to allocate network upgrade costs based on proportional impact.

434. PPL states that the NOPR did not address the allocation of network upgrade costs within a cluster after an interconnection customer withdraws.[877] PPL states that, prior to the execution of an interconnection agreement by the interconnection customer(s), the Commission should provide that any interconnection facility and network upgrade costs previously allocated to the withdrawing interconnection customer be reallocated among the remaining interconnection customers in the cluster to prevent delays and allow the study process to proceed. PPL states that the Commission should allow for withdrawal to be treated as an event that allows the transmission provider to retain or call on the

[875] EPSA Initial Comments at 8; Vistra Initial Comments at 12-13.

[876] Vistra Initial Comments at 13.

[877] PPL Initial Comments at 14.

security provided by the withdrawing interconnection customer. PPL adds that the Commission should allow for an increase in the cost allocated to remaining interconnection customers in a cluster to account for the amount previously allocated to the withdrawing interconnection customer.

(b) Tariff Requirement for Technical Details

435. PJM states that, while it generally supports the requirement to describe the cost allocation method in the applicable tariff, the Commission should clarify that transmission providers may provide the detailed and specific technical information in business practice manuals rather than in tariffs.[878] PJM states that these types of implementation details change from time to time and, consistent with Commission precedent, are appropriately addressed in the transmission provider's manuals. PJM asserts that mandating that these procedures be placed in the transmission provider's tariff, on the other hand, would require a transmission provider to submit an FPA section 205 filing every time the implementation details changed, which would be inefficient and burdensome.

436. In contrast, other commenters argue that these thresholds, and any associated procedures, should be codified in transmission providers' tariffs.[879] AES explains that the thresholds used as part of the proportional impact method are important planning

[878] PJM Initial Comments at 37.

[879] AES Initial Comments at 8; Union of Concerned Scientists Reply Comments at 20.

criteria, and constitute "practices that affect rates and services significantly, that are realistically susceptible of specification and that are not so generally understood as to render recitation superfluous;" accordingly, AES continues, they should be included in transmission providers' filed rates, and subject to review and approval by the Commission pursuant to section 205 of the FPA.[880] Union of Concerned Scientists contends that the combination of issues that are expressed through network upgrade decisions and cost allocations for interconnection customers are arguably central to this rulemaking and the fulfillment of the competition amongst interconnection customers as a regulatory approach to setting wholesale energy prices and must be subject to notice and review, both initially and for any subsequent changes, through filings with the Commission.[881]

437. Xcel states that the Commission should make clear that there are several just and reasonable approaches to allocating network upgrade costs to interconnection customers within a cluster.[882] For example, states Xcel, if two generating facilities are connecting to a new a transmission line, a substation must be constructed. Xcel explains that, using some analysis, a larger generating facility might be considered to have a larger impact, but the respective size of the interconnection request did not have any impact on the cost

[880] AES Initial Comments at 8 (citing *Pub. Serv. Co. of Colo.*, 67 FERC ¶ 61,371, at 62,267 (1994); *Portland Gen. Elec. Co.*, 144 FERC ¶ 61,087 (2013)).

[881] Union of Concerned Scientists Reply Comments at 20-21.

[882] Xcel Initial Comments at 26.

or size of the substation needed. Xcel states that, for example, the cost of the substation is not different for a 100 MW and 500 MW generating facility or for two 300 MW generating facilities if they are interconnecting at the same voltage, and as a result, the cost of that substation should be allocated equally to both generating facilities. Xcel states that there could be a third generating facility (not directly connected to the substation) from which the power flows through the new substation, but it is not clear if the Commission is proposing that the interconnection customer proposing that third generating facility pays for a portion of the substation costs because its flows "impact" the substation. Xcel states that it does not generally support allocating network upgrade costs to interconnection customers simply because their proposed generating facilities have a flow impact if they are not causing the need for the network upgrade under a "but for" evaluation.

438. Invenergy states that, in the occasional circumstance where a point of interconnection is shared among more than one interconnection request within a cluster, which could involve new equipment that does not vary based on proportional impact, the associated costs at the point of interconnection (e.g., the substation) could be allocated on a pro rata basis.[883] PacifiCorp states that the proportional impact method would not be necessary to account for costs that are agnostic to interconnection customer impacts, such

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[883] Invenergy Initial Comments at 21-22.

as the need to construct a new substation to connect to a new transmission line regardless of whether one or several generating facilities are interconnecting.[884]

439. Invenergy states that the NOPR could be read to permit each transmission provider to adopt different and possibly inconsistent analyses and that the Commission should be clear that it is requiring a proportional impact method for allocating network upgrade costs, just as the NOPR proposes to do with respect to shared network upgrades.[885]

440. Several commenters state that the final rule should require transmission providers to submit compliance filings that propose minimum distribution factor thresholds that will be used to evaluate NRIS and ERIS requests.[886]

(c) Requests for Flexibility

441. Some commenters support the proportional capacity method only for certain network upgrades or limited circumstances.

442. Tri-State states that it does not apply a proportional impact method to transient-stability-driven network upgrades, which cannot be measured using a proportional impact approach; rather, Tri-State uses a MW pro rata method approach when allocating the

[884] PacifiCorp Reply Comments at 2 (citing Xcel Initial Comments at 26 (describing how a proportional impact analysis is not necessary to allocate costs for a new station connecting to a transmission line, as "[t]he cost of the station is not different for a 100 MW and 500 MW generator or for two 300 MW generators if they are interconnecting at the same voltage")).

[885] Invenergy Initial Comments at 21.

[886] AEE Reply Comments at 10; AES Initial Comments at 8; Longroad Energy Initial Comments at 9; SEIA Initial Comments at 11.

costs of transient-stability-driven network upgrades.[887] Longroad Energy states that, to the extent the Commission allows a transmission provider to use some method other than a flow-based proportional impact allocation for transient stability constraints, the transmission provider should be required to demonstrate that the alternative cost allocation method is based on sound engineering principles for the specific transient stability constraint observed in the studies.[888]

443. R Street states that allocating network upgrade costs based on proportional capacity is appropriate in situations where clusters are composed of similar types of generation.[889] R Street asserts that the default should be that all thermal network upgrade cost allocations are based on proportional capacity. R Street states that this leaves open the possibility for transmission providers to allocate other types of network upgrade costs (voltage, transient stability, short circuit) using a different but predefined method.

444. Several commenters ask the Commission to provide flexibility for transmission providers to establish a cost allocation method for network upgrades, rather than mandating a prescriptive approach.[890] PPL claims that such region-specific cost

[887] PacifiCorp Reply Comments at 2; Tri-State Initial Comments at 12.

[888] Longroad Energy Initial Comments at 9.

[889] R Street Initial Comments at 12.

[890] AES Initial Comments at 7; APPA-LPPC Initial Comments at 16; Bonneville Initial Comments at 10; Dominion Initial Comments at 19; Indicated PJM TOs Initial Comments at 20; ISO-NE Initial Comments at 25; MISO Initial Comments at 45; National Grid Initial Comments at 8; NEPOOL Initial Comments at 15; New York State Department Initial Comments at 8; NYISO Initial Comments at 15; PPL Initial

allocations are necessary to keep disputes from overwhelming the reform process the Commission anticipates.[891] New York State Department asserts that any strict or limiting requirement for a specific cost allocation method may undermine and replace existing processes that work well.[892] National Grid recommends that the Commission allow for consideration of the unique circumstances of a region, input from relevant stakeholders in the region, including the potential for regions to propose cost allocation methods that allow for broader allocation to load or transmission customers in addition to interconnection customers.[893]

445. Dominion points out that courts and the Commission have long recognized that there is not one single just and reasonable method for establishing cost allocation.[894] Dominion states that rather, cost allocation proposals are reviewed to determine whether they meet certain principles, chiefly that costs are allocated in a manner that is at least "roughly commensurate" with estimated benefits received.[895] Accordingly, Dominion recommends that if the Commission imposes any requirements related to cost allocation,

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Comments at 14.

[891] PPL Initial Comments at 14.

[892] New York State Department Initial Comments at 8-9.

[893] National Grid Initial Comments at 18.

[894] Dominion Initial Comments at 19, 21 (citing *Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39, 50 (2003)).

[895] *Id.* at 19.

it simply retains a general definition of proportional impact method and is not overly prescriptive.[896]

iii. Requests for Clarification or Technical Conference

446. Pattern Energy generally supports the application of the proportional impact method, subject to clarification on which form of distribution factor analysis the Commission is contemplating.[897] Pattern Energy states that there are two types of distribution factors used to determine the impact of given power injection flows over a monitored facility: (1) power transfer distribution factor, which is the percentage of power that will flow on a specific monitored facility and does not consider outage/contingent facilities; and (2) outage transfer distribution factor, which is the percentage of power that will flow on a specific facility that does consider outage/contingent facilities. Pattern Energy states that the difference between the two distribution factors (i.e., the consideration of the outage/contingent facility) is important because power transfer distribution factor is usually more relevant for evaluating "local impacts" (e.g., generating facilities that are connecting in very close electrical proximity to a given monitored element), compared to outage transfer distribution factor, which captures impacts that may be more geographically and electrically distant from a given monitored facility. Pattern Energy asserts that the Commission should require outage transfer distribution factor to be the required distribution factor utilized in the

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[896] *Id.* at 22.

[897] Pattern Energy Initial Comments at 11-12.

proportional impact method for identifying impacts to constrained facilities and resultant cost allocation for network upgrades. Pattern Energy argues that outage transfer distribution factor is a better measure of power flows on the bulk-power system, and, in turn, its use ensures that impacts to constrained facilities are properly mitigated by, and cost allocated to, the actual, full set of contributors and not just the nearby highest contributors.

447. Pine Gate contends that certain proposed enhancements to the NOPR proposal would provide much needed certainty to interconnection customers and mitigate the systematic problem of interconnection queues being the primary mechanism by which needed transmission infrastructure is identified, developed, and constructed.[898] Specifically, Pine Gate requests that the Commission make the following clarifications: (1) transmission providers are not permitted to allocate to interconnection customers network upgrade costs associated with preexisting operating conditions (such as overloads); (2) transmission providers are not permitted to allocate network upgrade costs to interconnection customers for loading that results from the simulation of conditions that do not reflect typical operating conditions; (3) transmission providers are required to use consistent, uniform thresholds to measure the impact on a specific transmission facility caused by an interconnection request and publish these thresholds, along with the corresponding scope of the resulting network upgrades; and (4) establish a 4% impact threshold for NRIS and a 20% impact threshold for ERIS, unless there is preexisting

[898] Pine Gate Initial Comments at 16-17.

loading on the facility.[899] Pine Gate further requests that the Commission provide transmission providers guidance on the scope of the network upgrade required to accommodate an interconnection request. Pine Gate states that, if a network upgrade benefits other types of customers, interconnection customers should receive transmission credits or other compensation if the additional transmission capacity created is used for market dispatch or by wholesale transmission customers.[900] Pine Gate states that, if the Commission does not adopt Pine Gate's proposed enhancements as part of a final rule in this proceeding, then the Commission should establish a technical conference to explore these issues.

iv. Miscellaneous

448. Pennsylvania Commission states that limiting the scope of each cluster to those interconnection customers most likely to share the same network upgrades may reduce the need for the proportional impact network upgrade cost allocation method.[901] According to Pennsylvania Commission, instead of determining the degree to which interconnection requests cause specific network upgrades on the back end through cost allocation, clustering by electrical relevance may accomplish the same goal, making sure that interconnection customers are sharing the costs of network upgrades that they cause and from which they benefit. Pennsylvania Commission contends that the Commission

[899] *Id.* at 18-19.

[900] *Id.* at 20.

[901] Pennsylvania Commission Initial Comments at 9.

should examine whether limiting the scope of a cluster or cost allocation, or a combination of both, is the best method to share costs among interconnection customers causing the same network upgrades.

449. Several commenters state that the NOPR leaves unresolved the fundamental question of more equitably sharing network upgrade costs across all beneficiaries, including load.[902] They argue, for example, that policies requiring interconnection customers to pay for 100% of network upgrade costs when the benefits of those upgrades are distributed among other system users (i.e., participant funding) causes interconnection customers to pay more than their appropriate share of the costs.[903] In contrast, Ameren claims that it is appropriate for interconnection customers to bear responsibility for the cost of network upgrades required for their interconnection requests.[904] Ameren argues that, to ensure the full costs of interconnection are identified and allocated, network upgrade costs associated with affected systems must also be included in cluster network upgrade cost allocation, and interconnection customers should be required to accept the assigned costs. Ohio Commission Consumer Advocate emphasizes that the Commission

[902] ACORE Initial Comments at 8-9; AEE Initial Comments at 14-15; Interwest Initial Comments at 5; Northwest and Intermountain Initial Comments at 8; Public Interest Organizations Initial Comments at 31-33.

[903] AEE Initial Comments at 14 (citing Joint Supplemental Comments of American Clean Power Association, Advanced Energy Economy, and Solar Energy Industries Association, Docket No. RM21-17-000, at 7-8 (filed June 1, 2022)).

[904] Ameren Initial Comments at 12.

should not change the participant funding mechanisms in RTO/ISO markets,[905] while PPL argues that the Commission should allow non-RTO/ISO transmission providers the option to propose allocating the costs of network upgrades to interconnection customers without credits as RTOs/ISOs do.[906]

450. New York State Department and Shell argue that the Commission should discontinue the historical practice of allowing interconnection customers essentially free use of headroom on ratepayer-funded network facilities.[907] New York State Department states that this occurs when transmission ratepayers fund upgrades to the transmission system that create headroom, from which interconnection customers later benefit without having to pay for access or use.[908] In contrast, Invenergy asserts that the Commission needs to ensure that the transmission planning and interconnection models are consistent, so that interconnection customers are not required to pay for the cost of resolving overloads and other transmission system issues that exist without the proposed interconnection.[909]

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[905] Ohio Commission Consumer Advocate Initial Comments at 9.

[906] PPL Initial Comments at 13.

[907] New York State Department Initial Comments at 9; Shell Reply Comments at 27-28.

[908] New York State Department Initial Comments at 9.

[909] Invenergy Initial Comments at 21.

451. AEE encourages the Commission to ensure that its proposal increases cost transparency and establishes a pathway for interconnection customers to access accurate information about their network upgrade costs in a timely manner.[910] For instance, AEE asks that the Commission also provide guidance regarding which party must pay if network upgrade costs significantly exceed estimates. AEE states that one approach to minimizing the construction time and cost of network upgrades, and consequently the interconnection process as a whole, is to provide a third-party construction option in the *pro forma* LGIA that would allow the interconnection customer to elect for stand alone network upgrades to be bid out and potentially built by third parties.[911]

452. Pine Gate recommends that the Commission require transmission providers to analyze more holistically the other underlying needs driving identified network upgrades to the transmission system.[912] Pine Gate states that the Commission should require transmission providers to only allocate to interconnection customers the costs associated with accelerating the construction of the upgrade to accommodate the interconnection customer's anticipated commercial operation date.[913]

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[910] AEE Initial Comments at 15.

[911] *Id.* at 15-16 (citing Comments of AEE, Docket No. RM21-17-000, at47-49 (filed Oct. 12, 2021)).

[912] Pine Gate Initial Comments at 17.

[913] *Id.*; Fervo Energy Reply Comments at 5.

c. **Commission Determination**

453. We adopt the NOPR proposal, with modifications, to add new proposed section 4.2.3, now section 4.2.1, to the *pro forma* LGIP to require transmission providers to allocate network upgrade costs based on a proportional impact method.[914] Based on the record, we modify the NOPR proposal and add definitions for substation network upgrades and system network upgrades in the *pro forma* LGIP and *pro forma* LGIA. In addition, we modify the definitions of proportional impact method and stand alone network upgrades proposed in the NOPR. We also modify proposed section 4.2.1 of the *pro forma* LGIP to require transmission providers to allocate the costs of network upgrades located at substations equally among each generating facility interconnecting to the same substation (i.e., on a per capita basis), and to revise the information that a transmission provider's tariff must include regarding the proportional impact method.

454. We also modify the requirement in proposed section 4.2.1 of the *pro forma* LGIP for transmission providers to directly assign the cost of shared transmission provider's interconnection facilities to interconnection customers on a per capita basis (i.e., on a per generating facility basis). Specifically, we modify proposed section 4.2.1 of the *pro forma* LGIP to make the new provisions applicable to the interconnection customer's interconnection facilities as well as to the transmission provider's interconnection

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[914] "Proportional Impact Method shall mean a technical analysis conducted by Transmission Provider to determine the degree to which each Generating Facility in the Cluster Study contributes to the need for a specific System Network Upgrade." *Pro forma* LGIP section 1.

facilities. We also modify this section to provide that interconnection customers may agree to share interconnection facilities, and that the per capita allocation will apply only where interconnection customers agree to share interconnection facilities. We also modify this section to allow the interconnection customers that share interconnection facilities to choose a different cost sharing arrangement upon mutual agreement.

455. We find that adopting the modified NOPR proposal will ensure just and reasonable rates as transmission providers transition to the cluster study process required by this final rule. We find that the cost allocation method adopted herein will allow transmission providers to allocate network upgrade costs among several interconnection customers that may benefit from (and cause the need for) certain network upgrades. We also find that allocating shared network upgrade costs among a cluster of interconnection customers will reduce the frequency of an individual interconnection customer being allocated the costs of a large network upgrade that benefits subsequent interconnection customers; reduce the incentive of interconnection customers to submit multiple speculative interconnection requests to avoid shouldering the cost of large network upgrades that may be triggered by a single interconnection customer in the existing serial study process; and reduce the number of cascading withdrawals and restudies, thereby improving the efficiency of the interconnection process and reducing interconnection queue processing delays.

456. We conclude that a proportional impact method appropriately reflects the Commission's interconnection pricing policy for facilities designated as network upgrades needed for the interconnection of the cluster. However, we are persuaded to

adopt a different cost allocation method for substations at the point of interconnection that are designated as network upgrades and needed only to facilitate the interconnection of certain generating facilities within the cluster seeking interconnection to the specific substation, as demonstrated by commenters.[915]

457. In Order No. 2003, the Commission reasoned that "it is appropriate for the Interconnection Customer to pay the initial full cost for Interconnection Facilities and Network Upgrades that would not be needed but for the interconnection" (i.e., "but for" policy).[916] Hence, under the serial study process in the existing *pro forma* LGIP, the transmission provider allocates network upgrade costs by assigning the initial full cost responsibility for all network upgrades identified in a study to a single interconnection customer that causes those upgrades. However, in transitioning to a cluster study process in this final rule, the Commission must establish a method for allocating network upgrade costs among all interconnection customers within a cluster. Based on the record in this proceeding, we find that a proportional impact method is the appropriate application of the Commission's interconnection pricing policy when allocating the costs of network upgrades needed for an entire cluster of proposed generating facilities because a proportional impact method allows transmission providers to assess a generating

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[915] Xcel Initial Comments at 26; Invenergy Initial Comments at 21-22.

[916] *See id.* P 694; *Nev. Power Co.,* 182 FERC ¶ 61,048, at PP 50-51 (2023) (describing the cost allocation requirements for network upgrades as the Commission's Order No. 2003 "but for requirements").

facility's individual contribution to the need for the network upgrades identified for the cluster. However, the need for substation network upgrades is only generated by a specific generating facility seeking interconnection at a specific substation and not by all the generating facilities in the cluster. It would be inconsistent with the Commission's interconnection pricing policy to allocate the costs of the substation network upgrades to interconnection customers in the cluster that are interconnecting at other substations because, in the case of a cluster of new interconnection requests, only the generating facilities interconnecting to the same substation generate the need for network upgrades at that substation.

458. As explained above, the cost of substation network upgrades must be initially allocated only to those interconnection customers seeking to interconnect at the same substation,[917] while the cost of system network upgrades for all interconnection customers in a cluster must be initially allocated based on the technical analyses to be specified under the transmission provider's proportional impact method. To facilitate these differing cost allocation methods, we modify the definitions in section 1 of the *pro forma* LGIP and article 1 of the *pro forma* LGIA to distinguish substation network

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[917] For clarity, we note that we are referring to the transmission provider's substation immediately beyond the point of interconnection as defined in section 1 of the *pro forma* LGIP: "Point of Interconnection shall mean the point . . . where the interconnection facilities connect to the transmission provider's transmission system." *Pro forma* LGIP section 1 (Definitions).

upgrades (including all switching stations)[918] from system network upgrades.[919] Using these definitions, we further modify the *pro forma* LGIP and *pro forma* LGIA to draw this distinction and to ensure that the costs for the two types of network upgrades are allocated consistent with the Commission's interconnection pricing policy, which establishes the principles for allocating the costs of network upgrades.

459. We note that we are not modifying the *pro forma* LGIP's definition of facilities needed beyond the point of interconnection as network upgrades; rather, we are providing greater specificity with regard to how the costs of the two distinct types of network upgrades identified within a cluster study should be initially allocated. We find that this approach will also lead to greater transparency and ease of administering the cluster study process by establishing distinct guidelines for how the costs of the two types of network upgrades will be initially allocated within a cluster. Also, as commenters note, in instances where a point of interconnection is shared among more than one interconnection request within a cluster, the cost of the substation network upgrades is more directly impacted by the number of generating facilities proposing to interconnect there because the cost of the equipment used to interconnect generating facilities to substations does not vary based on the electrical characteristics of the interconnecting

[918] Substation network upgrades shall mean the network upgrades required at the substation located at the point of interconnection.

[919] System network upgrades shall mean the network upgrades required beyond the substation located at the point of interconnection.

generating facilities (e.g., the MW size of the generating facility, fuel type, or services provided).

460. To further implement this modification of the NOPR proposal, we modify the definition of stand alone network upgrades proposed in the NOPR to recognize that (1) a substation network upgrade may only be considered a stand alone network upgrade if it is needed to interconnect only one generating facility in the cluster and no other interconnection customer in that cluster is required to interconnect to the same substation network upgrades, and (2) the proportional impact analysis will be used in determining whether a system network upgrade is only needed for one generating facility in the cluster and can be considered a stand alone network upgrade. Our revisions also seek to prevent lengthy disputes over which interconnection customer has the right to exercise the option to build in instances where a network upgrade could qualify under the existing definition of a stand alone network upgrade, but the network upgrade is needed for multiple interconnection customers' generating facilities.

461. Several commenters request that the Commission provide more specificity and guidance regarding the specific thresholds and metrics that transmission providers are expected to submit on compliance.[920] In this final rule, we modify the proposed requirement in *pro forma* LGIP section 4.2.1 for transmission providers to revise their LGIPs on compliance to include specific thresholds and metrics. Instead, we direct

[920] Clean Energy Buyers Initial Comments at 9; Cypress Creek Initial Comments at 19; EPSA Initial Comments at 8; Invenergy Initial Comments at 21; Vistra Initial Comments at 12-13.

transmission providers on compliance to provide tariff provisions that describe, for each type of system network upgrade that a transmission provider would identify in the cluster study process (e.g., voltage support network upgrades or short circuit network upgrades), how the costs of each system network upgrade type will be allocated among the interconnection customers within the cluster. Transmission providers' revisions on compliance must provide that costs for a discrete network upgrade identified in the cluster study process (e.g., reconductoring a portion of a transmission line to accommodate the interconnection of several generating facilities in the cluster) are allocated to only the interconnection customers in the cluster that are shown through technical analyses to contribute to the need for the discrete network upgrade. For example, the transmission provider must propose tariff provisions similar to the following: (1) voltage support related network upgrades shall be allocated using a voltage impact analysis, which will identify each generating facility's contribution to the voltage violation; (2) short circuit network upgrade costs within a cluster will be allocated based on the impact from each generating facility within the cluster, on the constrained facilities under the most constraining fault in the relevant study case(s); or (3) the estimated costs of short circuit related general reliability network upgrades identified through a cluster study shall be assigned to all interconnection requests in that group study pro rata on the basis of the short circuit duty contribution of each generating facility.

462. PJM requests that the Commission clarify that transmission providers may provide the detailed and specific technical information in business practice manuals rather than in

tariffs.[921] In response, we find that, as noted above, transmission providers must provide tariff provisions that describe the method they will use for allocating costs of each type of network upgrade, but specific metrics and thresholds for implementing the allocation, or other specific technical information, may be included in business practice manuals, or publicly posted on the transmission provider's website. We agree with PJM that such details are appropriate for business practice manuals, consistent with Commission precedent applying the "rule of reason" to determine whether a detail should be included in a tariff or business practice manual. In particular, the technical information surrounding implementation of the proportional impact method by a particular transmission provider does not need to be included in the transmission provider's tariff under the rule of reason because these provisions are properly classified as implementation details that do not significantly affect rates, terms, and conditions of service.[922]

463. Several commenters request that the Commission direct transmission providers to use a specific type of proportional impact method or distribution factor analysis and apply minimum distribution factor thresholds that will be used to evaluate NRIS and ERIS requests.[923] We are unpersuaded that such level of prescription is needed to ensure

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[921] PJM Initial Comments at 37.

[922] *See, e.g.*, *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102, at PP 105-114 (2022) (citing, *inter alia*, *Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,296, at P 103 (2018); *City of Cleveland v. FERC*, 773 F.2d, 1368, 1376-77 (D.C. Cir. 1985)).

[923] AEE Reply Comments at 10; AES Initial Comments at 8; Invenergy Initial

just, reasonable, and not unduly discriminatory or preferential rates. Instead, we believe that flexibility for transmission providers to develop such details as part of their compliance filings—and in their business practice manuals, where consistent with the rule of reason, as discussed above—is important to ensure that the proportional impact method used by each transmission provider reflects the characteristics of its region (e.g., types of network upgrade facilities identified in the region, or preferred analyses in the region for determining the share of the need for the specific network upgrade type). For the same reason, we decline to require transmission providers to use consistent, uniform thresholds to measure impact, as requested by Pine Gate.[924]

464. Based on the record, we decline to require transmission providers to use the proportional capacity method to allocate the costs of all system network upgrades, given our decision to instead opt for the proportional impact method and because it reflects the Commission's interconnection pricing policy for facilities designated as network upgrades needed for the interconnection of the cluster. Nonetheless, we recognize that there may be a tradeoff between simplicity and accuracy when considering proportional capacity versus proportional impact for cost allocation for network upgrades. While we require transmission providers to allocate network upgrade costs based on a proportional impact method based on the record in this final rule, we acknowledge that other

Comments at 21; Longroad Energy Initial Comments at 9; Pattern Energy Initial Comments at 11-12; Pine Gate Initial Comments at 16-19; SEIA Initial Comments at 11.

[924] Pine Gate Initial Comments at 19.

allocation methods could potentially meet the consistent with or superior to standard or the independent entity variation standard if, among other things, they allocate network upgrade costs in a manner consistent with the Commission's interconnection pricing policy.

465. We disagree with NV Energy and PacifiCorp's arguments that the proportional impact method carries unmanageable time, restudy, and reallocation risks.[925] In response to concerns about restudy risk resulting from withdrawals, we note that the Commission's new cluster study process requires transmission providers to complete the process within 150 calendar days, which we believe is sufficiently long for transmission providers to be able to conduct the rounds of restudy and reallocation that are needed to achieve a stable interconnection queue and reduce the risk of further withdrawals before moving to the individual facilities studies. Further, the proportional impact method is currently used by most transmission providers that conduct cluster studies, and several of these transmission providers have adopted study timelines similar to what we adopt in this final rule.[926]

466. We disagree with claims from NV Energy and PacifiCorp that the proportional impact method must be conducted as if it were a serial study in that each interconnection

[925] NV Energy Initial Comments at 12; PacifiCorp Reply Comments at 3.

[926] *See Dominion Energy S.C., Inc.*, Docket No. ER22-301-000 (Dec. 28, 2021) (delegated order); *Duke Energy Carolinas, LLC*, 176 FERC ¶ 61,075 (2021); *Pub. Serv. Co. of Colo.*, 169 FERC ¶ 61,182 (2019); *Tri-State Generation & Transmission Ass'n, Inc.*, 173 FERC ¶ 61,015 (2020).

request must be studied individually. When proposing a proportional impact method on compliance, transmission providers have many methods to choose from and should adopt a method that allows them to meet the timelines designated in the cluster study process. In response to PPL,[927] we confirm that within the cluster study process, any network upgrade costs previously allocated to a withdrawing interconnection customer that are still required after the withdrawal may be reallocated among the remaining interconnection customers in the cluster based on the relevant cost allocation method applied to the network upgrade facility type.

467. Finally, several commenters suggest alternative reforms to the Commission's network upgrade cost allocation policies: (1) limit the use of cluster areas as an alternative to the proposed cost allocation method within a cluster;[928] (2) change the interconnection pricing policy or participant funding regime (as allowed in certain RTOs/ISOs) to limit participant funding and/or require assessment of whether transmission customers benefit from and should pay for network upgrades;[929] (3) establish a process to eliminate the use of headroom on network transmission facilities;[930]

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[927] PPL Initial Comments at 14.

[928] Pennsylvania Commission Initial Comments at 9.

[929] ACORE Initial Comments at 8-9; AEE Initial Comments at 14-15; Ameren Initial Comments at 12; Interwest Initial Comments at 5; Northwest and Intermountain Initial Comments at 8; Ohio Commission Consumer Advocate Initial Comments at 12; PPL Initial Comments at 13; Public Interest Organizations Initial Comments at 31-33.

[930] New York State Department Initial Comments at 9; Shell Reply Comments at 27-28.

and/or (4) provide a third-party construction option.[931] We find these requests to be outside the scope of this proceeding and lacking in record support to adequately consider whether to adopt them in this final rule.

5. Shared Network Upgrades

a. NOPR Proposal

468. In the NOPR, the Commission preliminarily found that the absence of network upgrade cost sharing provisions in the *pro forma* LGIP may pose a barrier to entry to generation development.[932] The Commission stated that absent cost sharing provisions among clusters, interconnection customers may significantly benefit from earlier-in-time network upgrades but not share in the cost of those network upgrades in a manner that is roughly commensurate with benefits. The Commission therefore proposed to require transmission providers to allocate the costs of network upgrades between interconnection customers in an earlier cluster and interconnection customers in a subsequent cluster that benefit from the same network upgrade in a manner that is roughly commensurate with the benefits received.[933] Specifically, the Commission proposed that when the transmission provider analyzes the network upgrades identified through its cluster study process, if a generating facility of an interconnection customer in a later cluster directly connects either to (1) a network upgrade in service for less than five years or (2) a

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[931] AEE Initial Comments at 15.

[932] NOPR, 179 FERC ¶ 61,194 at P 97.

[933] *Id.* P 98.

substation where the network upgrade in service for less than five years terminates, then the transmission provider would be required to designate the network upgrade a shared network upgrade. Upon such a designation, the interconnection customer in the later cluster would be required to contribute a pro rata portion of the shared network upgrade's remaining undepreciated capital cost based on the impact the interconnection customer in the later cluster has on the network upgrade, as measured using the same method the transmission provider used to determine the impact of the interconnection customer(s) in the earlier cluster.

469. The Commission proposed that if the new generating facility does not directly connect to the network upgrade, then the transmission provider would perform a power flow analysis with a two-step test to measure the lower-queued interconnection customer's use of and benefit from the network upgrade funded by interconnection customers from an earlier cluster. Under the first step, the transmission provider would determine if the impact of the interconnection customer in the later cluster exceeds five MW and exceeds one percent of the network upgrade's rating. Then, if those criteria are met, the transmission provider would determine if the lower-queued interconnection customer's impact either exceeds more than 5% of the network upgrade's facility rating or if the transmission distribution factor is greater than 20%. Finally, if either of these criteria were met, the transmission provider would be required to designate that network upgrade a shared network upgrade, and the interconnection customer in the later cluster would be responsible for a pro rata share of the network upgrade's remaining undepreciated capital cost based on the impact the interconnection customer in the later

cluster has on the network upgrade, as measured using the same method the transmission provider used to determine the impact of the interconnection customer(s) from the earlier cluster.

470. The Commission proposed to require the interconnection customer in the later cluster to pay the transmission provider for the interconnection customer's share of the shared network upgrade costs through a one-time lump sum, which the transmission provider would disburse to the appropriate interconnection customer(s) from the earlier cluster.[934] The Commission also proposed that, where applicable, the interconnection customer from the earlier cluster or the relevant transmission provider would be required to assign transmission credits for the portion of the shared network upgrade that the interconnection customer in the later cluster funded to the interconnection customer in the later cluster. Additionally, the Commission proposed to require that the interconnection customer in the later cluster not be required to pay for its share of the cost of the shared network upgrade until that shared network upgrade is in service. The Commission also proposed to require transmission providers to provide the list of shared network upgrades to interconnection customers in subsequent clusters at the conclusion of the cluster study and to list those network upgrades in the appendix of the relevant interconnection customer's LGIA. The Commission acknowledged that there could be scenarios where the network upgrade may be identified as both a shared network upgrade and a contingent facility; and, thus a designation of a network upgrade as a contingent facility does not

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[934] *Id.* P 99.

preclude it from also being a shared network upgrade if the network upgrade meets the aforementioned criteria and passes the screens.[935]

b. Comments

i. Comments in Support

471. Multiple commenters support the proposal.[936] OMS states that, while cost sharing arrangements can be resource intensive and contentious, they can be crucial to facilitating an equitable interconnection process.[937] NARUC states that the proposal is a logical extension of the cluster cost sharing concept and could spread costs over even more interconnection customers benefitting from network upgrades.[938] A couple of commenters contend that the proposal will provide more certainty and result in fewer withdrawals, thus reducing associated restudies and study processing delays.[939]

472. Several commenters believe that the proposal will address the issue of "first movers/free riders" when interconnection customers in a later cluster study benefit from

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[935] *Id.* P 100.

[936] AES Initial Comments at 12; Avangrid Initial Comments at 32; Bonneville Initial Comments at 11; Interwest Initial Comments at 17; ISO-NE Initial Comments at 25; MISO Initial Comments at 47; NARUC Initial Comments at 9; National Grid Initial Comments at 19; NESCOE Initial Comments at 9-10; New Jersey Commission Initial Comments at 15-16; NYTOs Initial Comments at 17; SEIA Initial Comments at 12; Shell Initial Comments at 27; Vistra Initial Comments at 1; Xcel Initial Comments at 27.

[937] OMS Initial Comments at 9.

[938] NARUC Initial Comments at 9.

[939] New Jersey Commission Initial Comments at 16; Omaha Public Power Initial Comments at 5-6; SEIA Initial Comments at 2.

network upgrades assigned to interconnection customers in earlier clusters.[940] Shell claims that avoiding first mover subsidization of free riders is particularly important for offshore wind interconnections because of the potential lack of onshore access points and, therefore, argues that the Commission should be open to non-traditional cost allocation methods when contemplating methods to mitigate first mover risk.[941]

473. Additionally, some commenters believe that the proposal is consistent with the Commission's cost causation policy.[942] Avangrid asserts that, when surplus transmission capacity created by a recent network upgrade is used by a later generating facility, the lower-queued interconnection customer should share the costs in a way that is commensurate with benefits like those allocated using the original proportional impact method assessment.[943]

474. Xcel does not believe the proposal will have a significant impact on the number of interconnection requests submitted but believes that it will reduce barriers to entry for all

[940] ELCON Initial Comments at 9; Longroad Energy Reply Comments at 13; Pattern Energy Initial Comments at 18; SEIA Initial Comments at 12; Shell Initial Comments at 27; Xcel Initial Comments at 27; Vistra Initial Comments at 4.

[941] Shell Initial Comments at 27.

[942] Avangrid Initial Comments at 32; Omaha Public Power Initial Comments at 5-6; Vistra Initial Comments at 5.

[943] Avangrid Initial Comments at 32.

interconnection customers.[944] Xcel believes that the proposal is appropriate where there is participant funding.

ii. <u>Comments in Opposition</u>

475. Some commenters oppose the proposal.[945] Several commenters assert that it will not yield many benefits and that the Commission should focus on other reforms that are more likely to reduce network upgrade costs and improve the equity of allocating them among beneficiaries.[946] Dominion and Fervo Energy argue that interconnection customers in subsequent clusters do not "cause" the costs to be incurred, and to the extent the interconnection customers will benefit, they will contribute through their payment for transmission service.[947]

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[944] Xcel Initial Comments at 48.

[945] APS Initial Comments at 11; Dominion Initial Comments at 22, 28; Dominion Reply Comments at 17; Duke Southeast Utilities Initial Comments at 9; EEI Reply Comments at 12-13; Enel Initial Comments at 30; Indicated PJM TOs Initial Comments at 21; PacifiCorp Initial Comments at 27; Pennsylvania Commission Initial Comments at 10; R Street Initial Comments 12; SPP Initial Comments at 8; U.S. Chamber of Commerce Initial Comments at 8.

[946] AEE Initial Comments at 16; Dominion Initial Comments at 23-24; Dominion Reply Comments at 17; Enel Initial Comments at 30; EEI Reply Comments at 12; Eversource Initial Comments at 15; Indicated PJM TOs Reply Comments at 40; PacifiCorp Initial Comments at 29; Pennsylvania Commission Initial Comments at 10; Pine Gate Initial Comments at 20; SoCal Edison Initial Comments at 17; SPP Initial Comments at 8; U.S. Chamber of Commerce Initial Comments at 8.

[947] Dominion Initial Comments at 23; Fervo Energy Reply Comments at 5-6.

476. Other commenters believe that the implementation of the proposal will be administratively burdensome for transmission providers.[948] A few commenters believe that the proposal will lead to increased disputes and FPA section 206 complaints at the Commission over cost allocation assignments.[949]

477. Several commenters express concern that the proposal will lead to interconnection study delays and/or restudies, which would undermine the NOPR's goal to reduce interconnection study processing timelines.[950] A few commenters state that the proposal would require transmission providers to track all in-service network upgrades on the transmission system across all cluster studies over a five-year period, which they contend would be onerous or nearly impossible.[951] The U.S. Chamber of Commerce claims that

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[948] AECI Initial Comments at 5; AEE Initial Comments at 16; APS Initial Comments at 11; CAISO Initial Comments at 15; Dominion Initial Comments at 23-24; Dominion Reply Comments at 17; Enel Initial Comments at 30; Indicated PJM TOs Initial Comments at 21-22; National Grid Initial Comments at 19; PacifiCorp Initial Comments at 27, 29; Pine Gate Initial Comments at 22; PJM Initial Comments at 37-38; R Street Initial Comments at 12; SPP Initial Comments at 8; U.S. Chamber of Commerce Initial Comments at 8.

[949] AECI Initial Comments at 5-6; Dominion Initial Comments at 23-24; Dominion Reply Comments at 18; Duke Southeast Utilities Initial Comments at 10; Fervo Energy Reply Comments at 5; PacifiCorp Initial Comments at 28; PJM Initial Comments at 37-38.

[950] CAISO Initial Comments at 13; Dominion Initial Comments at 23; Dominion Reply Comments at 17; Indicated PJM TOs Reply Comments at 40; PacifiCorp Initial Comments at 27-28; Pennsylvania Commission Initial Comments at 10; SPP Initial Comments at 9.

[951] APS Initial Comments at 11-12; Dominion Initial Comments at 22; Dominion Reply Comments at 17; PacifiCorp Initial Comments at 28; U.S. Chamber of Commerce Initial Comments at 8.

power flow studies conducted up to five years after the in-service date of non-adjacent network upgrades will inevitably fail to accurately divide the relevant interconnection costs among disparate-in-time interconnection customers due to the many coinciding yet unrelated system changes that will affect the outcomes of such analyses.[952] PacifiCorp contends that this requirement would require transmission providers to track multiple requests for each network upgrade on different timelines, the suspension or withdrawal of which could trigger cascading revaluations and corresponding LGIA amendments.[953] Dominion contends that the NOPR's proposal would complicate reviews and require additional time-consuming analysis, which would only worsen for transmission providers with a high volume of interconnection requests, such as RTOs/ISOs.[954]

478. Some commenters argue that the proposal will not create cost certainty for interconnection customers in earlier clusters when deciding whether to move forward with a generating facility because there would be no guarantee that an interconnection customer in a subsequent cluster would provide reimbursement.[955] NextEra and PJM

[952] U.S. Chamber of Commerce Initial Comments at 8.

[953] PacifiCorp Initial Comments at 28.

[954] Dominion Initial Comments at 23.

[955] AEE Initial Comments at 16; Clean Energy Associations Initial Comments at 25; Dominion Initial Comments at 23-24; EEI Initial Comments at 22; Enel Initial Comments at 30; Indicated PJM TOs Initial Comments at 22-23; Indicated PJM TOs Reply Comments at 40; NARUC Initial Comments at 9; NextEra Initial Comments at 18; Pine Gate Initial Comments at 22; PJM Initial Comments at 38; U.S. Chamber of Commerce Initial Comments at 8; Xcel Initial Comments at 48.

argue that a benefit of not sharing costs between clusters is that all the interconnection customers within a cluster simultaneously learn their network upgrade costs and associated cost responsibility, creating greater cost certainty.[956]

iii. Alternatives and Requests for Flexibility

479. Several commenters recommend modifications to the proposal.[957] A few recommend that the Commission implement a minimum threshold before a network upgrade would be evaluated as a potential shared network upgrade.[958] MISO and Xcel state that changes will be necessary in RTO/ISO regions where a transmission owner may unilaterally provide upfront funding for network upgrades to integrate the cost allocation for such a funding mechanism with the shared network upgrade proposal.[959] ENGIE recommends that the Commission set requirements in the interconnection process to identify interconnection facilities and network upgrades that are necessary to interconnect the generating facility, as well as network upgrades needed to mitigate local transmission constraints, and asserts that interconnection customers should not be responsible for the

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[956] NextEra Initial Comments at 18-19; PJM Initial Comments at 38.

[957] Clean Energy Associations Initial Comments at 25-26; ENGIE Reply Comments at 3-4; MISO Initial Comments at 48-49; Pattern Energy Initial Comments at 18; Xcel Initial Comments at 29.

[958] ENGIE Reply Comments at 3-4; MISO Initial Comments at 48; R Street Initial Comments 12; Xcel Initial Comments at 29.

[959] MISO Initial Comments at 48-49; Xcel Initial Comments at 29.

costs of distant and minimally impacted network upgrades.[960] Xcel also contends that the interconnection customer in the subsequent cluster should enter into a multiparty facilities service agreement to reimburse the interconnection customers in the earlier cluster, rather than pay the proposed lump sum payment to the transmission provider.[961] Pattern Energy recommends that the interconnection customer in the later cluster be required to repay the earlier interconnection customer at the time of execution of the subsequent interconnection customer's interconnection agreement, and not when the relevant shared network upgrades go into service.[962]

480. A few commenters propose alternative methods for cost allocation for shared network upgrades.[963] For instance, Xcel argues that the Commission should be clear that it will accept other proposals to determine if a network upgrade is shareable to subsequent interconnection requests.[964]

481. Some commenters support regional flexibility for transmission providers to implement any shared network upgrade mechanism.[965] For example, NESCOE suggests

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[960] ENGIE Reply Comments at 3-4.

[961] Xcel Initial Comments at 29.

[962] Pattern Energy Initial Comments at 18.

[963] Clean Energy Associations Initial Comments at 25; ENGIE Reply Comments at 3; Longroad Energy Reply Comments at 13; Pine Gate Initial Comments at 20, 23.

[964] Xcel Initial Comments at 28.

[965] Bonneville Initial Comments at 11; CAISO Initial Comments at 14; EEI Initial Comments at 22; Indicated PJM TOs Initial Comments at 21; Indicated PJM TOs Reply Comments at 40; National Grid Initial Comments at 19; NESCOE Initial Comments at

that allowing transmission providers, especially RTOs/ISOs, some flexibility in coordinating with their states on developing proposed approaches to sharing the costs associated with network upgrades funded by interconnection customers in earlier clusters could minimize the contentious nature of developing cost sharing arrangements.[966]

482. Other commenters recommend that the Commission not adopt the shared network upgrade proposal in non-RTO/ISO regions where interconnection customers provide upfront funds for the network upgrades and receive reimbursement through transmission credits from the transmission provider, plus interest (i.e., the interconnection pricing policy established in Order No. 2003).[967] Pine Gate states that under the NOPR proposal, interconnection customers in later clusters would potentially reimburse interconnection customers in earlier clusters sooner than the transmission provider would have via transmission credits, but with the same result.[968] Enel asserts that coupling shared network upgrades with transmission credits creates even more administrative complexity, as an interconnection customer in a later cluster providing funds to an interconnection customer in an earlier cluster would necessitate a partial transfer of transmission credits, potentially on a partially depreciated asset, which creates an extremely complex payment,

11; NESCOE Reply Comments at 7; NRECA Initial Comments at 9, 24; NYISO Initial Comments at 16; PJM Initial Comments at 37.

[966] NESCOE Initial Comments at 11.

[967] Duke Southeast Utilities Initial Comments at 10-11; Enel Initial Comments at 30; PacifiCorp Initial Comments at 26-28; Pine Gate Initial Comments at 22.

[968] Pine Gate Initial Comments at 22.

reimbursement, and multiparty crediting system that would be administratively burdensome.[969] Similarly, APS and Duke Southeast Utilities express concern over an additional complication in the event the earlier interconnection customer has already been fully reimbursed for the network upgrades through transmission credits.[970] In contrast, Vistra contends that the shared network upgrade proposal will be beneficial in regions with transmission crediting as it will speed reimbursement relative to the status quo.[971] Vistra claims that, when an overlap exists between the reimbursement of an interconnection customer through transmission credits and the reimbursement mechanism in this proposal, this proposal will appropriately charge interconnection customers in subsequent clusters.

483. Other commenters raise additional cost allocation concerns with the shared network upgrade proposal. Enel argues that, in markets where transmission credits do not apply, reimbursement for funding network upgrades is often granted in the form of congestion hedging mechanisms, and the repayment of network upgrade costs from a lower-queued interconnection customer to a higher-queued interconnection customer could create the need for a partial transfer of these congestion hedging rights.[972] SDG&E cautions against allowing scenarios where an higher-queued interconnection customer

[969] Enel Initial Comments at 30.

[970] APS Initial Comments at 12; Duke Southeast Utilities Initial Comments at 10.

[971] Vistra Initial Comments at 5.

[972] Enel Initial Comments at 30.

with cost responsibility terminates an executed LGIA but the network upgrades are still needed for later interconnection customers, thus leaving the transmission provider as the backstop for financing the network upgrade.[973] A few commenters argue that the Commission should limit its proposal to share network upgrade costs between clusters to areas whether interconnection customers are not already reimbursed for network upgrade costs.[974]

484. Several commenters note that some RTOs/ISOs have similar existing cost allocation mechanisms to the NOPR proposal and request that, in those instances, the Commission defer to those transmission providers when the existing mechanisms are accomplishing the final rule's objectives.[975] On a similar note, PJM and Indicated PJM TOs request that the Commission not require PJM to implement cost sharing between its clusters.[976]

485. Several commenters request various clarifications of the proposal and provide their thoughts on specific aspects.[977]

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[973] SDG&E Initial Comments at 6.

[974] CAISO Initial Comments at 13; SoCal Edison Initial Comments at 16.

[975] Ameren Initial Comments at 13; APPA-LPPC Initial Comments at 17; ISO-NE Initial Comments at 26; MISO Initial Comments at 47-48; NYISO Initial Comments at 15; NYTOs Initial Comments at 17; OMS Initial Comments at 9; SDG&E Initial Comments at 5.

[976] Indicated PJM TOs Initial Comments at 23; PJM Initial Comments at 37.

[977] APS Initial Comments at 11-12; Avangrid Initial Comments at 32-33; Clean Energy Associations Initial Comments at 25; Fervo Energy Initial Comments at 4; Fervo Energy Reply Comments at 4; LADWP Initial Comments at 4; Pattern Energy Initial

c. **Commission Determination**

486. We decline to adopt the NOPR proposal to revise the *pro forma* LGIP and *pro forma* LGIA to implement shared network upgrades between interconnection customers in an earlier cluster and interconnection customers in a subsequent cluster. We find that the reforms adopted in this final rule that require transmission providers to allocate network upgrade costs to interconnection customers within the same cluster using a proportional impact method, as discussed above, will provide interconnection customers with more cost certainty during the interconnection process and will allow for sharing of network upgrade costs between interconnection customers that benefit from those network upgrades within the same cluster.

487. The record demonstrates the complexity of the NOPR proposal and potentially significant administrative burdens associated with implementing it for at least some transmission providers, especially under the Commission's interconnection pricing policy. We agree with some commenters that adopting the proposal would not provide cost certainty to interconnection customers in earlier clusters at the point that they have to proceed in the interconnection process because they would lack certainty about potential reimbursement for network upgrades from interconnection customers in subsequent clusters.[978] Thus, the NOPR proposal is unlikely to reduce barriers to generation

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Comments at 18; Pine Gate Initial Comments at 21-22; Tri-State Initial Comments at 12, 34; Vistra Initial Comments at 5.

[978] AEE Initial Comments at 16; Clean Energy Associations Initial Comments at 25; Dominion Initial Comments at 23-24; EEI Initial Comments at 22; Enel Initial Comments at 30; Indicated PJM TOs Initial Comments at 22-23; Indicated PJM TOs

development due to the absence of network upgrade cost sharing provisions. Further, the proposal may introduce burdens for lower-queued interconnection customers that could be faced with reimbursing a higher-queued interconnection customer for a new shared network upgrade cost late in the interconnection process. For these reasons, we decline to adopt this NOPR proposal.[979]

488. We find that the final rule's reforms to conduct cluster studies and to allocate the costs of any assigned network upgrades to the cluster's interconnection customers on a proportional basis address the "first mover/free rider" issue.[980] Under this final rule, a transmission provider must study interconnection customers in an earlier cluster study based on the transmission system at that time, and those interconnection customers will be assigned network upgrades that would not be needed but for their interconnection to the transmission system; then, the transmission provider will study interconnection customers in a subsequent cluster study based on the transmission system at that point in time, and those interconnection customers will be assigned any necessary network

Reply Comments at 40; NARUC Initial Comments at 9; NextEra Initial Comments at 18; Pine Gate Initial Comments at 22; PJM Initial Comments at 38; U.S. Chamber of Commerce Initial Comments at 8; Xcel Initial Comments at 48.

[979] We note that MISO, ISO-NE, and NYISO, which have independent entity variations to the Commission's crediting policy, have similar shared network upgrade mechanisms to the NOPR proposal. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221, at P 336 (2010); *ISO New England Inc.*, 161 FERC ¶ 61,123, at PP 92-96 (2017); *N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,238, at P 34 (2008).

[980] *See* ELCON Initial Comments at 9; Longroad Energy Reply Comments at 13; Pattern Energy Initial Comments at 18; SEIA Initial Comments at 12; Shell Initial Comments at 27; Vistra Initial Comments at 4; Xcel Initial Comments at 27.

upgrades that would not be needed but for their interconnection to the transmission system. Further, we note that under the Commission's interconnection pricing policy, interconnection customers receive reimbursement for network upgrade costs, which helps to mitigate any "first mover/free rider" concerns because interconnection customers are reimbursed through transmission credits. In addition, we find that the aforementioned reforms to conduct cluster studies and use a proportional impact method to allocate the costs of network upgrades within a cluster will also address "first mover/free rider" concerns in regions with independent entity variations to the interconnection pricing policy.

489. Because we decline to adopt this proposal, we do not respond to the requests for clarification or the requests for modifications to the NOPR proposal that would not address the reasons provided above for declining to adopt the NOPR proposal as a general matter.

6. Increased Financial Commitments and Readiness Requirements

490. In the NOPR, the Commission stated that the *pro forma* LGIP allows an interconnection customer to proceed through the generator interconnection process without having shown evidence to the transmission provider of meaningful progress toward achieving commercial viability.[981] The Commission stated its concern that, without requiring this type of evidence, interconnection customers will continue to submit multiple speculative interconnection requests and later withdraw those requests,

[981] NOPR, 179 FERC ¶ 61,194 at P 102.

triggering rounds of restudies. The Commission therefore proposed a set of reforms to adopt more stringent financial commitments and readiness requirements for interconnection customers to remain in the interconnection queue to discourage speculative interconnection requests and allow transmission providers to focus on processing viable interconnection requests and to better approximate the cost of the interconnection study process.[982]

a. Increased Study Deposits

i. NOPR Proposal

491. In the NOPR, the Commission proposed to adopt the following study deposit framework in the *pro forma* LGIP:[983]

Size of Proposed Generating Facility Associated with Interconnection Request	Amount of Deposit
> 20 MW < 80 MW	$35,000 + $1,000/MW
≥ 80 MW < 200 MW	$150,000
≥ 200 MW	$250,000

492. The Commission proposed to require transmission providers to collect this study deposit before each phase of the new first-ready, first-served cluster study process (i.e., cluster study, cluster restudy, and facilities study).[984] The Commission proposed to require the interconnection customer to provide: (1) an initial study deposit along with its

[982] *Id.* P 103.

[983] *Id.* P 106.

[984] *Id.* P 107.

interconnection request, which will be used to pay for the cluster study; (2) the second study deposit of the same amount within 20 days of receiving the cluster study report from the transmission provider to cover the cost of any clustered restudies; and (3) the third study deposit of the same amount along with its executed facilities study agreement. The Commission explained that study deposits would be refundable, and that the transmission provider would refund any portion of the study deposits above the applicable study costs and withdrawal penalties once the interconnection customer executes the LGIA, requests the filing of an unexecuted LGIA and submits the corresponding payment discussed below, or withdraws from the interconnection queue. The Commission also proposed to delete section 8.1.1 of the *pro forma* LGIP to remove the requirement for transmission providers to invoice interconnection customers on a monthly basis for the work conducted on the facilities study.

493. The Commission sought comment on whether: (1) the proposed study deposit amounts accurately estimate the cost of conducting cluster studies; and (2) to adopt additional provisions or a different framework that would require larger proposed generating facilities to provide a higher deposit amount—such as a per MW framework.[985]

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[985] *Id.* P 110.

ii. <u>Comments</u>

494. Several commenters fully support the NOPR proposal to increase study deposits in order to support more effective interconnection queue management and reduce speculative interconnection requests.[986]

495. Other commenters express qualified support for the proposal.[987] For example, ELCON, New York Commission and NYSERDA, and NextEra contend that it is important that such measures be carefully balanced so that they are not overly burdensome or discouraging to interconnection customers with legitimate proposed

[986] AEP Initial Comments at 20; APPA-LPPC Initial Comments at 18; CAISO Initial Comments at 15-16; Consumers Energy Initial Comments at 5; EEI Initial Comments at 6-7; NARUC Initial Comments at 10; NYTOs Initial Comments at 17; Pennsylvania Commission Initial Comments at 14; SoCal Edison Initial Comments at 5; U.S. Chamber of Commerce Initial Comments at 8; UMPA Initial Comments at 5; Vistra Initial Comments at 6.

[987] ACE-NY Initial Comments at 4; AES Initial Comments at 14; Ameren Initial Comments at 14; APPA-LPPC Initial Comments at 18; APS Initial Comments at 13; Avangrid Initial Comments at 16; Bonneville Initial Comments at 11; CESA Initial Comments at 8-9; Clean Energy Associations Initial Comments at 30; Cypress Creek Initial Comments at 20; Dominion Initial Comments at 24; EEI Initial Comments at 6; ELCON Initial Comments at 10; ENGIE Initial Comments at 4; Eversource Initial Comments at 16; Google Initial Comments at 20; Fervo Energy Initial Comments at 4; Idaho Power Initial Comments at 6; ISO-NE Initial Comments at 27; MISO Initial Comments at 49; National Grid Initial Comments at 20; NESCOE Reply Comments at 8, 10; New York Commission and NYSERDA Initial Comments at 8; NextEra Initial Comments at 20; NRECA Initial Comments at 25; NV Energy Initial Comments at 14; NYISO Initial Comments at 19-20; Omaha Public Power Initial Comments at 6; Pacific Northwest Utilities Initial Comments at 4; PJM Initial Comments at 24; PPL Initial Comments at 15; SEIA Initial Comments at 13; Southern Initial Comments at 8-9; SPP Initial Comments at 9; Tri-State Initial Comments at 4, 12.

generating facilities that may be delayed for reasons out of their control.[988] Clean Energy Associations do not oppose the heightened study deposit requirements, provided that they are paired with real predictability on the timing of studies and real certainty on the costs of network upgrades.[989] CAISO argues that the Commission must raise study deposits significantly, and contends that it is illusory to argue that interconnection customers without significant capital can progress to commercial operation in today's hyper-competitive climate.[990] PPL asserts that the Commission's proposed study deposits are likely on the low end of what is required to ensure proper "skin in the game," but should work for many regions, including New England.[991] Tri-State overall supports the proposed study deposit amounts but notes that interconnection customers proposing smaller generating facilities will end up paying a lower study deposit than what Tri-State is currently charging.[992] ENGIE, MISO, and SPP would prefer to collect study deposits only once upon entry into the cluster, rather than at each stage of the cluster study

[988] ELCON Initial Comments at 10; New York Commission and NYSERDA Initial Comments at 8-9; NextEra Initial Comments at 20.

[989] Clean Energy Associations Initial Comments at 30.

[990] CAISO Initial Comments at 15-16.

[991] PPL Initial Comments at 15 (noting that PJM's interconnection queue reform proposal includes higher deposits, ranging from $75,000 to $400,000 and a 10% nonrefundable component).

[992] Tri-State Initial Comments at 12.

process, to reduce administrative burden on them and the interconnection customers.[993] MISO and Shell argue that limiting speculative interconnection requests and ensuring more concrete financial readiness would be better achieved by requiring a single study deposit at the initiation of the generator interconnection process.[994] Shell urges the Commission to base that deposit on the generating facility's size.

496. Several commenters argue that the final rule should provide each region with flexibility concerning the scope and application of any modifications to increased study deposits.[995] Indicated PJM TOs contend that the transmission provider should be entitled to adjust the study deposit value if it observes that the actual cost of studies tends to be materially higher or lower.[996] Dominion adds that the Commission should respect the previously accepted reforms made by transmission providers like Dominion and PJM with regard to study deposits.[997]

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[993] ENGIE Initial Comments at 4; MISO Initial Comments at 50; SPP Initial Comments at 9.

[994] MISO Initial Comments at 51; Shell Initial Comments at 17; Shell Reply Comments at 22.

[995] Avangrid Initial Comments at 17; Bonneville Initial Comments at 11; Dominion Initial Comments at 24; Indicated PJM TOs Reply Comments at 29; Interwest Reply Comments at 12; ISO-NE Initial Comments at 28; National Grid Initial Comments at 21; New York Commission and NYSERDA Initial Comments at 9; NESCOE Reply Comments at 9-10; NRECA Initial Comments at 26; NYISO Initial Comments at 19; Pacific Northwest Utilities Initial Comments at 2; SPP Initial Comments at 10.

[996] Indicated PJM TOs Reply Comments at 29.

[997] Dominion Initial Comments at 24.

497. APS suggests that any refundable deposits should not include the Commission interest rate and argues that, by requiring additional funds to be deposited as described in the NOPR, the Commission's proposal would lead to an exorbitant increase in the amount of Commission interest paid back to an interconnection customer as it moves along through the process at the transmission provider's expense.[998]

498. Other commenters mostly oppose the NOPR proposal to increase study deposits.[999] CREA and NewSun agree that a tiered study deposit level tied to interconnection capacity requested may be warranted and at most study deposits should be increased to more accurately cover the cost of the studies, but comment that the rest of the NOPR's proposal appears to increase the study deposit levels solely to deter interconnection customers from entering the interconnection queue, not because the current level of study deposits is insufficient to cover the costs of the studies.[1000] CREA and NewSun argue that, if this rulemaking generates evidence that the current study deposit levels are insufficient to cover the typical costs of studies, an increase may be justified, but until then, study deposits should not be increased. Eversource recommends that the Commission consider making the rate of increase per MW more gradual, and that based on the current proposed figures, the deposits may increase too quickly relative to

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[998] APS Initial Comments at 13.

[999] CREA and NewSun Initial Comments at 51-52; Eversource Initial Comments at 16; rPlus Initial Comments at 5; RWE Renewables Initial Comments at 2.

[1000] CREA and NewSun Initial Comments at 51-52.

generating facility size.[1001] rPlus argues that study deposit requirements are unduly discriminatory or punitive to pumped storage as compared to other renewable technologies because a large capacity pumped storage facility would expect to hit the maximum deposit and/or penalty in every stage of the interconnection study process, LGIA, and potential withdrawal.[1002] RWE Renewables fully supports allocating some risk for each generating facility entered into the interconnection queue to interconnection customers, but argues that increased financial deposits have unfortunately not been an adequate deterrent to a high volume of non-viable generating facilities entering into the interconnection queues.[1003]

499. In response to the Commission's request for comment on whether the proposed study deposit amounts accurately estimate the cost of conducting cluster studies, Ameren states that, based on its experience, the proposed study deposits are in line with the cost of conducting the cluster studies.[1004] Xcel contends that the proposed study deposits are more than the cost of studies in its experience, but as studies will need to be accelerated under the Commission's proposal (to meet timelines) and may involve more actions, the proposed study cost may be appropriate.[1005] NV Energy states that, on average, it spends

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[1001] Eversource Initial Comments at 16.

[1002] rPlus Initial Comments at 5.

[1003] RWE Renewables Initial Comments at 2.

[1004] Ameren Initial Comments at 14.

[1005] Xcel Energy Initial Comments at 29-30.

between $80,000 and $100,000 between the cluster system impact study and facilities studies and refunds the remaining deposits with interest.[1006] Cypress Creek comments that in its experience, study costs can vary widely depending on the transmission provider, the staff resources it has available to conduct the study, and whether it needs to contract with external resources to conduct the study.[1007]

500. CREA and NewSun urge the Commission to maintain a lower study deposit prior to obtaining the initial cluster study. They argue that larger study deposits are only justified once the interconnection customer can realistically assess the commercial viability of its proposed generating facility within the cluster after obtaining the potential interconnection costs.[1008] Fervo Energy contends that more information is needed before one can conclude that the proposed study deposit amount framework would not result in deposits that far exceed the actual cost of the studies, particularly in light of the withdrawal penalty proposal.[1009] Cypress Creek suggests that the Commission should provide additional justification and argues that the NOPR fails to provide any further justification for study costs (i.e., based on a market analysis or other method), stating

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[1006] NV Energy Initial Comments at 14.

[1007] Cypress Creek Initial Comments at 20-21.

[1008] CREA and NewSun Initial Comments at 53.

[1009] Fervo Energy Initial Comments at 4.

only that the proposed amounts "better approximate the cost of the interconnection study process."[1010]

501. In response to the Commission's request for comment on whether the Commission should adopt additional provisions or a different framework that would require larger proposed generating facilities to provide a higher study deposit amount, such as a per MW framework, PJM contends that the Commission should adopt readiness payments or study deposits based on the costs of the network upgrades necessary to interconnect the generating facilities in the cluster, which also contain "at-risk" non-refundable provisions.[1011]

iii. <u>Commission Determination</u>

502. We adopt, with modification, the NOPR proposal to require interconnection customers to pay, and transmission providers to collect, study deposits as part of the cluster study process.[1012] Specifically, we adopt the NOPR proposal to require the following study deposit framework in section 3.1.1.1 of the *pro forma* LGIP:

[1010] Cypress Creek Initial Comments at 20 (quoting NOPR, 179 FERC ¶ 61,194 at P 103).

[1011] PJM Initial Comments at 24.

[1012] Here, we refer to initial study deposits separately from the LGIA deposit. We discuss the latter in Section III.A.6.d below. In the NOPR, the Commission discussed the deposits together, NOPR, 179 FERC ¶ 61,194 at P 109, although the proposed *pro forma* LGIP treated the initial study deposit, proposed *pro forma* LGIP section 3.1.1.1 (Initial Study Deposit), separate from the LGIA deposit, proposed *pro forma* LGIP section 3.1.1.3 (LGIA Deposit).

Size of Proposed Generating Facility Associated with Interconnection Request	Amount of Deposit
> 20 MW < 80 MW	$35,000 + $1,000/MW
≥ 80 MW < 200 MW	$150,000
≥ 200 MW	$250,000

503. However, we modify the NOPR proposal to require transmission providers to collect a single study deposit only once upon entry into the cluster (initial study deposit), rather than requiring transmission providers to collect a study deposit at each phase of the cluster study process, as proposed in the NOPR. Therefore, we decline to adopt the proposed revisions to sections 3.1.1.2, 7.5, and 8.1 of the *pro forma* LGIP that would have implemented the phased study deposit approach. As a result of this modification to the NOPR proposal, the initial study deposit will be required only at the time the interconnection customer submits an interconnection request. The amount of the initial study deposit will be calculated using the tiered approach proposed in the NOPR based on the proposed MW size of the generating facility, as shown in the chart above.

504. We adopt the tiered approach based on the proposed MW size of the generating facility for determining the amount of the initial study deposit because larger proposed generating facilities within a cluster generally cost more to study than smaller proposed generating facilities within a cluster. Further, although we acknowledge that this approach does not perfectly approximate study costs, we find it appropriate to require the transmission provider to collect a study deposit based on a tiered approach because study costs will be trued up and any excess deposit refunded once the interconnection customer

executes the LGIA or requests the filing of an unexecuted LGIA and submits the corresponding payment discussed below or withdraws from the interconnection queue.

505. We modify the NOPR proposal to require only a single initial study deposit, rather than multiple deposits at different stages of the cluster study process, as proposed in the NOPR. We believe that this modification will appropriately reduce the administrative burden for transmission providers to collect and manage the deposits.[1013] We recognize that the amount of the study deposit for interconnection customers will be lower than that proposed in the NOPR because of this modification. We are persuaded by commenters' arguments that initial study deposits are best used to provide transmission providers with funds to cover the costs of studies performed for interconnection customers rather than to serve as a disincentive against speculative interconnection requests.[1014] We therefore adopt an initial study deposit framework that better reflects the costs of the interconnection studies. For example, NV Energy states that, on average, it spends between $80,000 and $100,000 between the cluster system impact study and facilities studies and refunds the remaining deposits with interest.[1015] Under the study deposit framework we adopt, study deposits range between $55,000 and $250,000 for the smallest and largest proposed generating facilities, respectively, and thus reasonably track

[1013] *See* ENGIE Initial Comments at 4; MISO Initial Comments at 50; SPP Initial Comments at 9.

[1014] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 220.

[1015] NV Energy Initial Comments at 14.

likely study costs based on the record. We believe that other reforms adopted in this final rule—notably, the commercial readiness deposits and the site control requirements—will adequately serve as a disincentive against speculative interconnection requests without unnecessarily duplicating those efforts through increased study deposits.

506. Additionally, we adopt the NOPR proposal to delete section 8.1.1 of the *pro forma* LGIP to remove the requirement for transmission providers to invoice interconnection customers on a monthly basis for the work conducted on the facilities study. We find that this monthly invoicing requirement is burdensome to the transmission provider and unnecessary given that section 13.3 of the *pro forma* LGIP includes policies for invoicing and establishes that interconnection customers are responsible for the actual costs of interconnection studies. Accordingly, we also delete from *pro forma* LGIP Appendix 3 (Interconnection Facilities Study Agreement), the portion of article 5.0 that includes the monthly invoicing requirement.

507. We disagree with rPlus' argument that study deposit requirements are unduly discriminatory or punitive to pumped storage because of its large capacity.[1016] We note that the initial study deposit reforms we adopt in this final rule are agnostic to the type of generating facility. Rather, the initial study deposits are based on the MW size of the proposed generating facility, regardless of the type of generating facility, such that interconnection customers proposing larger generating facilities will pay a larger deposit. As explained above, this reflects the fact that the expected costs to study those generating

[1016] *See* rPlus Initial Comments at 5.

facilities are generally higher. Nonetheless, the modification we adopt here has the effect of lowering the required study deposit for all interconnection customers relative to the NOPR proposal, a finding which may partially allay rPlus' concern.

b. Demonstration of Site Control

i. NOPR Proposal

508. In the NOPR, the Commission stated that it believed that more stringent site control requirements will help prevent interconnection customers from submitting interconnection requests for speculative, commercially non-viable proposed generating facilities.[1017] The Commission preliminarily found that an interconnection customer securing the exclusive land right necessary to construct its proposed generating facility (or for co-located resources, demonstration of shared land use) is sufficient evidence of the interconnection customer's commitment to construct the generating facility.

509. The Commission proposed to revise the *pro forma* LGIP to require interconnection customers to demonstrate 100% site control for their proposed generating facilities when they submit their interconnection request.[1018] The Commission proposed

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[1017] NOPR, 179 FERC ¶ 61,194 at P 115.

[1018] *Id.* P 116. The Commission proposed the following definition of 'site control' in the NOPR:

> "Site Control shall mean the exclusive land right to develop, construct, operate, and maintain the Generating Facility over the term of expected operation of the Generating Facility. Site Control may be demonstrated by documentation establishing: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size to construct and operate the Generating Facility or multiple Generating Facilities on a shared site behind one Point of Interconnection; (2) an option to purchase or acquire a leasehold

to have transmission providers include in their tariff specific acreage requirements for each generating facility technology type to demonstrate site control.

510. To cut down on multiple interconnection customers leasing the same site in order to remain in the interconnection queue, the Commission proposed to revise the *pro forma* LGIP to require interconnection customers to demonstrate the exclusive land right (where the land rights are exclusive to the interconnection customer, not necessarily the individual generating facility) to develop, construct, operate, and maintain its generating facility or, where facilities are co-located, to demonstrate a shared land use right to develop, construct, operate, and maintain co-located facilities.[1019]

511. Additionally, the Commission proposed to include a limited option for interconnection customers to submit a deposit in lieu of site control when they submit their interconnection request only when regulatory limitations prohibit the interconnection customer from obtaining site control.[1020] The Commission explained that in such instances, the interconnection customer would submit an initial deposit in lieu of site control of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million,

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site for such purpose; (3) site of sufficient size to construct and operate the Generating Facility; or (4) any other documentation that clearly demonstrates the right of Interconnection Customer to exclusively occupy a site of sufficient size to construct and operate the Generating Facility. Site Control for any Co-Located Resource is demonstrated by a contract or other agreement demonstrating shared land use for all Co-Located Resources that meet the aforementioned provisions of this Site Control definition."

[1019] *Id*. P 117.

[1020] *Id*. P 118.

which would be applied toward any interconnection studies or a withdrawal penalty, if applicable. The Commission specified that such an interconnection customer must demonstrate 100% site control prior to the facilities study. The Commission further proposed that, after the interconnection customer notifies the transmission provider of a change to its site control demonstration, the transmission provider must give the interconnection customer 10 business days to demonstrate that the site control demonstration meets the applicable requirement after notification.[1021]

512. The Commission sought comment on: (1) whether there are other specific situations in which the Commission should accept a deposit in lieu of site control; (2) whether the definition of site control, including the requirement to obtain an exclusive land right (or, for co-located resources, a shared land right), should be broadened or refined to account for circumstances that may arise in, for example, the siting and permitting of offshore resources in bodies of water and/or submerged land; (3) whether and how the definition of site control should be adjusted for interconnection customers to account for any regulatory requirements they may have associated with proposed generating facilities developed on sites owned or physically controlled by a state government entity and/or a federal government entity; (4) the appropriate stage in developing such sites when the Commission should view completion of such stage as indicative of an interconnection customer's request being non-speculative and whether there are substantive differences among interconnection customers developing sites

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[1021] *Id*. P 119.

owned or physically controlled by a state government entity and/or a federal government entity; (5) whether the Commission should allow transmission providers to accept demonstrations of less than 100% site control in the initial phases of the interconnection study process, outside of when regulatory limitations prohibit the interconnection customer from obtaining site control; and (6) whether the Commission should instead adopt site control provisions that allow a deposit in lieu of site control to enter the generator interconnection process and be evaluated under the first-ready, first-served cluster study process described above but require interconnection customers to demonstrate site control to enter the facilities study.[1022]

ii. Comments

(a) General Comments

513. Several parties generally support the proposal to increase site control requirements.[1023] These commenters generally agree that the proposal is reasonable and

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[1022] *Id.* PP 121-123.

[1023] AEP Initial Comments at 21; AES Initial Comments at 15; Ameren Initial Comments at 15-16; APPA-LPPC Initial Comments at 17-18; Avangrid Initial Comments at 9, 18-19; Bonneville Initial Comments at 11; CAISO Initial Comments at 16; Consumers Energy Initial Comments at 5; Dominion Reply Comments at 15; ELCON Initial Comments at 10; Enel Initial Comments at 40-42; Eversource Initial Comments at 16; Fervo Energy Reply Comments at 6; GSCE Initial Comments at 1; Hydropower Commenters Initial Comments at 12; Interwest Energy Alliance Reply Comments at 13; Invenergy Initial Comments at 9; Longroad Energy Initial Comments at 12; MISO Initial Comments at 53; NARUC Initial Comments at 10; NRECA Initial Comments at 27; NV Energy Initial Comments at 15; NYTOs Initial Comments at 18-19; Ørsted Initial Comments at 10; Pacific Northwest Utilities Initial Comments at 4; PG&E Initial Comments at 4; Pattern Energy Initial Comments at 29-30; Pine Gate Initial Comments at 23; PJM Initial Comments at 21-22; SEIA Initial Comments at 14; SoCal Edison Initial

that these measures can reduce speculative interconnection requests, represent a reasonable financial burden, help ensure that the interconnection customer is ready to enter the interconnection queue,[1024] help load serving entities have generating facilities interconnected as quickly and efficiently as possible,[1025] and reduce harm to other interconnection customers that have successfully secured site control for their proposed generating facility.[1026]

514. CREA and NewSun, on the other hand, argue that the Commission's proposed site control requirements are anti-competitive because they allow utilities to erect market barriers to competitors' generating facilities and because the requirements bar investment by companies seeking to develop generating facilities using a merchant generation model.[1027]

Comments at 6; Tri-State Initial Comments at 13-15; U.S. Chamber of Commerce Initial Comments at 8; UMPA Initial Comments at 5; Xcel Initial Comments at 32.

[1024] Enel Initial Comments at 40.

[1025] Ameren Initial Comments at 15-16.

[1026] PJM Initial Comments at 29.

[1027] CREA and NewSun Reply Comments at 46.

(b) Comments on Specific Proposal

(1) Definition and Reasonable Evidence of Site Control

515. Some commenters support the proposed definition of site control.[1028] MISO notes that the proposed requirement for exclusivity or the demonstration of a right to co-locate generating facilities is in MISO's current tariff and that these requirements have proven to be successful at preventing speculative interconnection requests from entering or continuing in the interconnection queue.[1029]

516. Some commenters suggest modifications to the definition of site control. ENGIE and Tri-State recommend that the Commission consider requirements similar to MISO's requirements to identify when and whether an interconnection request is non-speculative.[1030] Xcel supports modifying the definition of site control to ensure exclusivity and allow for co-ownership.[1031]

517. PJM requests that the Commission clarify that interconnection customers are prohibited from submitting evidence of site control that uses the same land for multiple

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[1028] MISO Initial Comments at 53; National Grid Initial Comments at 22.

[1029] MISO Initial Comments at 53.

[1030] ENGIE Initial Comments at 5; Tri-State Initial Comments at 14.

[1031] Xcel Initial Comments at 31.

interconnection requests, unless the site is large enough to host multiple generating facilities.[1032]

518. Enel supports the proposal to require land rights that are exclusive to one development company, but not necessarily to the individual generating facility.[1033] According to Enel, when used regarding land rights, "exclusive" means that only the owner of those land rights can possess the property, and this interpretation could prevent co-located resources from being built if one parent company was using two separate special purpose vehicles for two different generating facilities sharing land. Enel therefore recommends that the Commission clarify the intent of this word so that it does not artificially restrict multi-use applications.

519. Cypress Creek believes that, to the extent the Commission intends that a "land right" should involve zoning approval, such a proposal would be unreasonable because interconnection customers do not typically initiate local permitting until the system impact study phase, due to the system impact study's impact to overall generating facility commercial viability.[1034]

520. Southern requests that the Commission clarify subpart (3) of the proposed site control definition, arguing that, as written, it appears to be an incomplete statement that may authorize an interconnection customer to simply provide evidence that a site is big

[1032] PJM Initial Comments at 31.

[1033] Enel Initial Comments at 42 (referencing NOPR, 179 FERC ¶ 61,194 at P 117).

[1034] Cypress Creek Initial Comments at 22.

enough to host a proposed generating facility rather than evidence that the interconnection customer actually has any rights to that property.[1035] Enel argues that subpart (3) to the definition should be deleted, because as modified, that item is duplicative of and a subset of the materials covered under subpart (1).[1036]

521. Other parties request that the Commission clarify the definition of site control to specify what constitutes reasonable evidence to demonstrate 100% site control[1037] or provide suggestions for what should be considered reasonable evidence of site control.[1038] NYISO requests that the final rule establish uniform requirements across regions for making the 100% site control determination.[1039] APS requests that the Commission specify what is considered reasonable evidence in the same manner that the Commission defines commercial readiness milestones and argues that clarification is needed in order to avoid subjectivity regarding what is considered "reasonable" evidence to the transmission provider.[1040]

[1035] Southern Initial Comments at 34-35.

[1036] Enel Initial Comments at 82.

[1037] APS Initial Comments at 7; NYISO Initial Comments at 21-22; Omaha Public Power Initial Comments at 7.

[1038] EPSA Initial Comments at 8; National Grid Initial Comments at 22; NRECA Initial Comments at 27; Omaha Public Power Initial Comments at 7; SoCal Edison Initial Comments at 6.

[1039] NYISO Initial Comments at 21-22.

[1040] APS Initial Comments at 7.

522. Omaha Public Power requests that the Commission clarify whether transmission providers will be able to accept lease options, instead of executed leases, as sufficient evidence of site control.[1041] Omaha Public Power notes that it has become industry standard to use lease options and argues that the Commission should not enact a rule that conflicts with current industry standard practices. SoCal Edison supports the NOPR proposal, provided that 100% site control includes an option to lease up to, and including, the commercial operation date or acquire the land when the interconnection request is submitted.[1042]

523. EPSA advises the Commission to consider options to demonstrate site control, including requiring attestations that a lessee or potential owner is in exclusive negotiations to establish site control, though it generally supports the development of clearer demonstrations.[1043] Interwest Energy Alliance recommends that the Commission consider evidence of active negotiations as potentially a sufficient demonstration of site control before the closing of the cluster request window.[1044]

524. SoCal Edison recommends that the Commission consider requiring that site control agreements be between the site owner and the same legal entity that is submitting

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[1041] Omaha Public Power Initial Comments at 7-8.

[1042] SoCal Edison Initial Comments at 6.

[1043] EPSA Initial Comments at 8.

[1044] Interwest Energy Alliance Reply Comments at 13.

the interconnection request.[1045] SoCal Edison explains that it has run into challenges when trying to determine whether interconnection customers have exclusive site control, in part due to the fact that companies change over time with renaming and/or mergers.

525. NRECA suggests that demonstration of site control with exclusive land rights should be allowed to include provisions that such rights are contingent upon favorable interconnection study results, inclusive of cost and schedule.[1046] NRECA notes that site control land options on many occasions come with a caveat that the lessee or purchaser has the ability to terminate within a due diligence period if interconnection results are unfavorable due to cost or schedule.[1047]

526. NV Energy requests clarification on whether an interconnection request should be deemed withdrawn if the interconnection customer does not provide demonstration of site control by the execution of the facilities study agreement.[1048]

527. Ørsted urges the Commission to clarify that, for offshore wind projects, the definition of "exclusive site control of the entire generating facility" means exclusive control of the Bureau of Ocean Energy Management (BOEM) issued offshore wind lease area, not cable routes on state submerged land or onshore cable routes to the point of

[1045] SoCal Edison Initial Comments at 6.

[1046] NRECA Initial Comments at 27.

[1047] *Id.* at 27 n.70.

[1048] NV Energy Initial Comments at 15.

interconnection.[1049] Ørsted reasons that, due to the extensive state and federal permitting process, offshore wind developers may not have authorization in the form of permits or other land use rights for portions of the offshore wind project on state submerged land or for the offshore and onshore cable routes during the interconnection process.

528. NYTOs and Pacific Northwest Utilities argue that it is unclear what would constitute 100% site control and therefore regions should be allowed to implement appropriate definitions for their regions on compliance to address their specific circumstances.[1050]

529. ISO-NE states that its existing LGIP and SGIP provisions, which are consistent with those proposed in the NOPR, have proven to be effective, and that the Commission should extend flexibility so that they may be maintained.[1051] Similarly, Indicated PJM TOs argue that the final rule should permit PJM to implement its 2022 interconnection queue reform proposal for demonstrating site control, which is more rigorous than the NOPR proposal.[1052]

[1049] Ørsted Initial Comments at 14.

[1050] NYTOs Initial Comments at 19; Pacific Northwest Utilities Initial Comments at 4.

[1051] ISO-NE Initial Comments at 29.

[1052] Indicated PJM TOs Initial Comments at 25 (citing PJM Interconnection, L.L.C., Tariff Revisions for Interconnection Process Reform, Docket No. ER22-2110-000 (filed June 14, 2022)). The Commission conditionally accepted PJM's filing on November 29, 2022 and accepted PJM's associated compliance filing on February 2, 2023. *See PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162 (2022), *order on reh'g*, 184 FERC ¶ 61,006 (2023); *PJM Interconnection, L.L.C.*, Docket No. ER22-2110-003

530. Several parties support the NOPR proposal to define 100% site control as an acreage requirement specific to the generating facility type and to require these acreage requirements in the tariff.[1053] Enel states that inclusion of acreage requirements in the tariff gives the Commission visibility into regional requirements to ensure that no transmission provider is significantly out of line with national assumptions.[1054]

531. Several commenters request that the Commission create a process by which an interconnection customer can demonstrate that its generating facility requires a different amount of acreage than the default value listed in the tariff.[1055] AES predicts that this approach will help ensure viable generating facilities are not inadvertently removed from the interconnection queue.[1056] MISO states that its tariff also allows an interconnection customer to demonstrate that it can operate the proposed generating facility with fewer acres.[1057] National Grid believes that regional flexibility would certainly be required for each transmission provider's proposed acreage requirements and requests clarification

(Feb. 2, 2023) (delegated letter order).

[1053] AES Initial Comments at 15; Enel Initial Comments at 42; NYISO Initial Comments at 21; Tri-State Initial Comments at 13.

[1054] Enel Initial Comments at 42.

[1055] AES Initial Comments at 16; Clean Energy Associations Initial Comments at 32-33; Public Interest Organizations Initial Comments at 27.

[1056] AES Initial Comments at 16.

[1057] MISO Initial Comments at 54.

accordingly.[1058] Some commenters suggest that transmission providers be required to update the acreage requirements periodically to reflect technological advancements.[1059]

532. Other parties oppose the NOPR proposal to require specific acreage requirements in the tariff[1060] or suggest that these requirements should be included in business practice manuals rather than tariffs.[1061] Some commenters argue that these acreage requirements will likely change with technology advances, and it would be burdensome if transmission providers are required to submit an FPA section 205 filing every time they need to change acreage requirements.[1062] Fervo Energy argues that the risk in this proposal is that the acreage requirements may understate the energy density of a generating facility and thus overstate the number of acres required for a given number of MW, resulting in discriminatory treatment between competing generation technologies.[1063]

533. Ørsted recommends that transmission providers use the most recent estimates of power density from BOEM when establishing acreage requirements for offshore wind

[1058] National Grid Initial Comments at 23.

[1059] Clean Energy Associations Initial Comments at 32-33; Longroad Energy Initial Comments at 12; Pattern Energy Initial Comments at 29-30.

[1060] EPSA Initial Comments at 8; Fervo Energy Initial Comments at 4; Ørsted Initial Comments at 11; Pine Gate Initial Comments at 24-25; PJM Initial Comments at 30.

[1061] MISO Initial Comments at 53-54; Pine Gate Initial Comments at 24-25; PJM Initial Comments at 30; Tri-State Initial Comments at 13.

[1062] Ørsted Initial Comments at 11; PJM Initial Comments at 30; Pine Gate Initial Comments at 24-25.

[1063] Fervo Energy Initial Comments at 4.

projects.[1064] Ørsted notes that offshore wind turbines have grown much larger in recent years, which allows significantly more power production from the same amount of acreage, and they argue that if transmission providers' tariffs were not updated frequently enough, the acreage requirements may become unreasonable.

534. Pine Gate recommends that acreage requirements specifically address how the requirements will be applied to hybrid and co-located generating facilities.[1065]

535. Some commenters request that the Commission clarify whether the site control requirement is limited to the generating facility or whether it also applies to transmission system elements like interconnection facilities or other upgrades that may be identified through the interconnection study process.[1066] Several parties argue that, for the initial request and study phase, 100% site control should not apply to land required to finalize routes for generator ties lines.[1067] AES argues that interconnection customers require flexibility when siting generator tie lines, which usually occurs near the very end of the interconnection process.[1068] Enel notes that there are sometimes crossings of railroads,

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[1064] Ørsted Initial Comments at 11.

[1065] Pine Gate Initial Comments at 24-25.

[1066] Interwest Energy Alliance Reply Comments at 13; NYISO Initial Comments at 22.

[1067] ACE-NY Initial Comments at 5; AES Initial Comments at 15; Avangrid Initial Comments at 18; Clean Energy Associations Initial Comments at 32; Enel Initial Comments at 41; ENGIE Initial Comments at 5; Equinor Reply Comments at 3; rPlus Initial Comments at 2-3; Shell Reply Comments at 23.

[1068] AES Initial Comments at 15.

streams, or other circumstances that require considerable time to complete and are outside the interconnection customer's control.[1069] AEE explains that issues can occur when interconnection customers have all but one small parcel on the route of their generating facility secured, with only one small piece of connectivity missing due to permitting delays or other issues.[1070] Similarly, Invenergy argues that it is unreasonable and impractical to predict and obtain rights to land for facilities that have not yet been identified.[1071] Invenergy also states that the point of interconnection can change during the study process, thus changing the land needs for the interconnection customer's interconnection facilities, and this change may be driven by a number of different factors, including the transmission provider's preference, which may be outside the interconnection customer's control.

536. Ørsted, ACE-NY, and Equinor Wind note a myriad of challenges for obtaining site control for interconnection facilities for offshore wind projects, such as conflicts between federal and state permitting entity requirements for project flexibility and adaptability.[1072]

[1069] Enel Initial Comments at 41.

[1070] AEE Initial Comments at 17.

[1071] Invenergy Initial Comments at 10.

[1072] ACE-NY Initial Comments at 5; Equinor Reply Comments at 4; Ørsted Initial Comments at 13; Ørsted Reply Comments at 2, 4, 5; Shell Reply Comments at 29.

Ørsted argues that site control for interconnection facilities for offshore wind developers is only obtainable very late in the interconnection process.[1073]

537. Other commenters argue that the Commission should expand the proposed definition of site control to apply some degree of site control requirements to interconnection facilities, such as a requirement to demonstrate 50% site control for interconnection facilities when submitting the interconnection request.[1074] MISO encourages the Commission to require site control for interconnection facilities at the same time that it requires site control for the generating facilities.[1075] AEP explains that some interconnection customers submit interconnection requests that are not feasible given where interconnection customer interconnection facilities would have to be sited to connect the generating facility to the transmission system at the selected point of interconnection.[1076] Additionally, AEP explains that, even if a generation site is suitable, there may not be "room" at certain locations for a substation or switchyard due to a variety of issues, including abandoned mines, surrounding wetlands, or other geographic impediments.[1077] According to AEP, site control for generating facilities can be far less

[1073] Ørsted Initial Comments at 12.

[1074] AEE Initial Comments at 18; AEP Initial Comments at 21-23; Cypress Creek Initial Comments at 22; Enel Initial Comments at 41; MISO Initial Comments at 56; National Grid Initial Comments at 22-23; Shell Reply Comments at 23.

[1075] MISO Initial Comments at 56.

[1076] AEP Initial Comments at 22.

[1077] *Id.* at 23.

important than feasible control over the land needed to connect the generating facility to the transmission system.

538. Enel argues that the addition of a generator tie line site control requirement will increase the quality of interconnection study results and increase certainty for interconnection customers as the interconnection process becomes more costly and risky to navigate.[1078] Enel states that it has observed or heard of interconnection customers submitting existing site control from very remote locations to secure interconnection queue positions, and later submitting a modification request to move the generating facility site close to the point of interconnection after the generating facility's actual intended site control has been obtained. Enel states that this is done by interconnection customers to reduce the duration and subsequently the cost of maintaining site control, as a failed distant asset can be used for a new interconnection queue position elsewhere until site control for the new generating facility area is complete. In addition, Enel states that it supports SPP's approach, which also requires 75% of generator tie line site control after the first cluster restudy, to ensure interconnection customers are making reasonable progress.

539. National Grid argues that demonstrating site control for interconnection facilities is crucial for generating facility development and interconnection queue management particularly in cases where numerous interconnection requests in the interconnection

[1078] Enel Initial Comments at 41-42.

queue are reliant on the construction of certain network upgrades.[1079] National Grid argues that the payment of cash or the provision of other security in lieu of demonstration of site control of transmission owner interconnection facilities or network upgrades built by an interconnection customer does not further the goals of the NOPR.

(2) Site Control Demonstration

540. Several commenters support the NOPR proposal to require interconnection customers to demonstrate 100% site control for their proposed generating facilities when they submit their interconnection request.[1080] MISO argues that obtaining site control is consistent with the "first-ready, first-served" model and that delaying site control for interconnection requests until later in the interconnection process just increases the instances of late-stage withdrawals that leads to uncertainty, unplanned restudies, and delays for the remaining interconnection requests.[1081] National Grid asserts that the demonstration of complete and exclusive site control is necessary at the interconnection request stage to avoid submission of interconnection requests prematurely, potential conflicts with other interconnection requests, and delays in issuing cluster studies.[1082] GSCE contends that there should be few exceptions to a site exclusivity requirement to

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[1079] National Grid Initial Comments at 23.

[1080] ACE-NY Initial Comments at 5; APS Initial Comments at 14; MISO Initial Comments at 56; National Grid Initial Comments at 22; Ørsted Initial Comments at 12.

[1081] MISO Initial Comments at 56-57.

[1082] National Grid Initial Comments at 22.

enter the cluster study process so leniency is not granted to the type of interconnection requests that linger in the interconnection queue while they struggle to secure difficult land rights and permitting.[1083]

541. PJM opposes any requirement on transmission providers to accept demonstrations of less than 100% site control at the time of an interconnection request, except for accommodations for interconnection requests for proposed generating facilities to be sited offshore or on government owned land.[1084]

542. MISO notes that its tariff requires redemonstrations of site control.[1085] Similarly, Indicated PJM TOs support requiring 100% site control at more than one decision point,[1086] and assert that transmission providers should be allowed to confirm site control throughout the interconnection process.[1087] Indicated PJM TOs and Longroad Energy argue that the Commission should strengthen the proposed site control requirements to ensure that interconnection customers are maintaining site control throughout the interconnection process.[1088]

[1083] GSCE Initial Comments at 7.

[1084] PJM Initial Comments at 32.

[1085] MISO Initial Comments at 53.

[1086] Indicated PJM TOs Initial Comments at 26 (citing PJM Interconnection, L.L.C., Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C., Docket No. ER22-2110-000, at 20 (filed Aug. 2, 2022)).

[1087] *Id.* at 8, 26.

[1088] Indicated PJM TOs Reply Comments at 30; Longroad Energy Reply Comments at 18.

543. On the other hand, APS believes that simultaneous submission of the interconnection customer-executed LGIA and the continued demonstration of site control is duplicative and unnecessary if an interconnection customer demonstrates site control at the time an interconnection request is made.[1089]

544. Several commenters oppose the NOPR proposal to require an interconnection customer to demonstrate 100% site control at the time of the interconnection request and/or propose alternative site control requirements.[1090] A number of commenters express concern that the NOPR proposal is not compatible with the generating facility development cycle.[1091] EPSA argues that a 100% exclusive site control requirement in advance of the processing of the facilities study is not reasonable because it overlooks the complicated and extensive process of negotiating for land leases or purchases.[1092] Similarly, Cypress Creek and AEE argue that the NOPR proposal does not reflect realities of development, which include stringent permitting requirements, and may

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[1089] APS Initial Comments at 7.

[1090] AEE Initial Comments at 17-18; Clean Energy Associations Initial Comments at 31-32; CREA and NewSun Initial Comments at 54; Cypress Creek Initial Comments at 22; EPSA Initial Comments at 8; NextEra Initial Comments at 21; Pine Gate Initial Comments at 24; R Street Initial Comments at 8; SEIA Initial Comments at 15; Shell Reply Comments at 23-24.

[1091] AEE Initial Comments at 17; Clean Energy Associations Initial Comments at 31; CREA and NewSun Initial Comments at 54; Cypress Creek Initial Comments at 22; EPSA Initial Comments at 8; NextEra Initial Comments at 21; R Street Initial Comments at 8.

[1092] EPSA Initial Comments at 8.

disadvantage certain interconnection customers despite being on a path to full site control and commercial readiness.[1093] CESA and Clean Energy Associations argue that the requirement for 100% site control at the interconnection request stage is excessively stringent and would significantly favor utility-owned projects.[1094]

545. CREA and NewSun argue that the NOPR proposal is not adequately supported and urge the Commission to maintain the existing site control requirements.[1095] CREA and NewSun argue that the proposal is unreasonable and "creates a Catch-22": specifically, that without reliable visibility as to the interconnection costs and viability for its proposed generating facility within the specific cluster, the interconnection customer will not be able to attract investment needed to secure site control. CREA and NewSun also argue that a landowner hoping to see property developed may not agree to permanently tie up land in a lease before the interconnection customer can show interconnection is viable. CREA and NewSun argue that interconnection requests may prove uneconomic after receipt of initial interconnection studies and thereafter cannot finalize site control due to uneconomic interconnection costs. CREA and NewSun also assert that the Commission made no effort in the NOPR to ascertain the impact on the market of the "draconian" site control rules for such transmission providers that have been allowed to adopt them.

[1093] AEE Initial Comments at 17.

[1094] CESA Reply Comments at 5.

[1095] CREA and NewSun Initial Comments at 54-55.

546. R Street argues that requiring even partial site control at the time of the interconnection request may create delays and increase project development costs because it would require more options contracts to be in place with landowners.[1096] NextEra argues that site control is a limited indicator of generating facility viability.[1097] rPlus argues that requiring 100% site control at the interconnection request stage will inhibit the flexibility for interconnection request design changes that is needed to develop pumped storage projects.[1098]

547. Several commenters recommend that the Commission modify the site control requirements in the final rule to require less than 100% site control at the time of the interconnection request. For example, Clean Energy Associations, SEIA, and Cypress Creek argue that no more than 75% site control is appropriate at the time of the interconnection request.[1099] Shell argues that the Commission should only require partial site control when the interconnection request is made.[1100] Clean Energy Associations supports an escalating schedule of site control through the interconnection process and suggests that the Commission should modify the NOPR proposal to also require 90% site

[1096] R Street Initial Comments at 13.

[1097] NextEra Initial Comments at 21-22.

[1098] rPlus Initial Comments at 2.

[1099] Clean Energy Associations Initial Comments at 31-32; Cypress Creek Initial Comments at 22; SEIA Initial Comments at 15.

[1100] Shell Reply Comments at 23-24.

control at the post-cluster study decision point and 100% site control at the post-facilities study decision point.[1101]

548. AEE argues that 90% site control at the time of the interconnection request provides interconnection customers sufficient flexibility.[1102] Additionally, several commenters state that 100% site control at the post-facilities study decision point would be appropriate.[1103] AEE argues that these altered requirements will reduce speculative interconnection requests while also providing incentive for interconnection customers to pursue remaining land rights after entering the interconnection queue.[1104]

549. Some commenters note that less than 100% site control at the interconnection request stage would allow interconnection customers flexibility to address the results of interconnection studies or other regulatory processes, which may lead to changes in the size or design of a generating facility.[1105] Additionally, SEIA requests that the Commission require transmission providers to allow interconnection customers to change site boundaries or reduce the size of a proposed generating facility, as long as the point of interconnection remains the same, in order to accommodate changes resulting from

[1101] Clean Energy Associations Initial Comments at 31-32.

[1102] AEE Initial Comments at 18.

[1103] *Id.*; CESA Reply Comments at 5-6; Clean Energy Associations Initial Comments at 31-32; Cypress Creek Initial Comments at 22; Xcel Initial Comments at 32.

[1104] AEE Initial Comments at 18.

[1105] CREA and NewSun Initial Comments at 55; SEIA Initial Comments at 14-15.

interconnection studies or regulatory changes.[1106] Pine Gate notes that sometimes interconnection customers are still actively negotiating with landowners close to the deadline for a cluster review window and requests the Commission to permit interconnection customers to demonstrate to the transmission prover that they are in active negotiations to meet the heightened site control requirements.[1107]

550. Some commenters highlight that the NOPR proposal may be problematic or challenging for interconnection customers of certain technology types or other circumstances where obtaining site control is difficult. Hydropower Commenters argue that most new hydropower facilities are sited at existing non-powered dams and therefore hydropower interconnection customers face unique challenges when it comes to obtaining site control.[1108] The Ohio Commission Consumer Advocate asserts that the proposal may be problematic for interconnection customers in Ohio because a recent Ohio law permits Ohio counties to designate unincorporated areas in a county as an area in which the development of a renewable energy project is prohibited.[1109]

[1106] SEIA Initial Comments at 15.

[1107] Pine Gate Initial Comments at 23-24. Pine Gate notes that this approach is similar to PJM's where, if PJM accepts the interconnection customer's demonstration, then PJM will add a condition precedent to the interconnection agreement requiring that all site control requirements be met within 180 days of execution.

[1108] Hydropower Commenters Initial Comments at 13.

[1109] Ohio Commission Consumer Advocate Initial Comments at 11.

551. According to Enel, some states limit the duration of site control.[1110] Enel asserts that, if site control is near to expiring for any reason, whether due to state restriction or simply because the interconnection customer did not anticipate the length of interconnection or permitting processes, landowners can demand higher payments than agreed to in the original site control contract. Enel states that this can change the economics of a proposed generating facility and even make a proposed generating facility unprofitable, potentially leading to a late-stage interconnection request withdrawal.

552. Several commenters argue that the Commission should reject proposals to weaken the site control requirements proposed in the NOPR.[1111] APPA-LPPC argue that EPSA's and SEIA's generalized complaints do not identify a specific obstacle created by the Commission's proposal, and APPA-LPPC argue that SEIA's proposal to scale back the site control requirement to not more than 75% was considered and rejected by MISO's management and stakeholders over concerns that it may not be rigorous enough to mitigate the entry of speculative interconnection requests in the queue.[1112]

[1110] Enel Initial Comments at 40.

[1111] APPA-LPPC Reply Comments at 2-3; CREA and NewSun Initial Comments at 55; Indicated PJM TOs Reply Comments at 30; Ohio Commission Consumer Advocate Initial Comments at 11-12.

[1112] APPA-LPPC Reply Comments at 4 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,173, at P 9 (2019)).

(3) <u>Deposits in Lieu of Site Control</u>

553. Several commenters support the NOPR proposal to eliminate the option for interconnection customers to submit a deposit in lieu of site control except in limited circumstances for regulatory limitations.[1113] These commenters express that allowing deposits in lieu of site control is not sufficient to demonstrate readiness or deter speculative interconnection requests.[1114] PJM notes that, in its experience, the option to provide money in lieu of actual site control is easily abused by interconnection customers with speculative interconnection requests.[1115] CAISO notes that its most recent cluster study was inundated by interconnection requests without site control because even a $250,000 deposit in lieu of site control has not proven to be a deterrent for interconnection customers.[1116]

[1113] AES Initial Comments at 15; APPA-LPPC Reply Comments at 4; CAISO Initial Comments at 16-17; CREA and NewSun Reply Comments at 50; Cypress Creek Initial Comments at 22; Dominion Initial Comments at 31; ENGIE Initial Comments at 4; EEI Initial Comments at 7-8; Eversource Initial Comments at 17; MISO Initial Comments at 57; NY Commission and NYSERDA Initial Comments at 8-9; NYTOs Initial Comments at 18-19; Ohio Commission Consumer Advocate Initial Comments at 12; SEIA Initial Comments at 15; Shell Initial Comments at 23; Tri-State Initial Comments at 13.

[1114] APPA-LPPC Initial Comments at 19; Bonneville Initial Comments at 11; Idaho Power Initial Comments at 7; PJM Initial Comments at 26; PPL Initial Comments at 16; Southern Initial Comments at 8-9; Xcel Initial Comments at 30, 32.

[1115] PJM Initial Comments at 26.

[1116] CAISO Initial Comments at 17.

554. Some commenters oppose the NOPR proposal and argue that the option to make deposits in lieu of site control should be available for all interconnection customers, not just those that demonstrate regulatory limitations.[1117] Avangrid believes that an at-risk deposit in lieu of site control that is set at a reasonable magnitude may be a good alternative to ensure that an interconnection customer is rigorously pursuing completion of a proposed generating facility.[1118] Pacific Northwest Utilities suggest that the Commission should allow transmission providers the flexibility to determine whether deposits in lieu of site control are applicable.[1119]

(4) <u>Site Control Considerations for Interconnection Customers with Regulatory Limitations</u>

555. Some commenters contend that the Commission should modify the proposed definition of site control to reasonably accommodate interconnection customers developing generating facilities on sites owned or controlled by a government entity.[1120] Several commenters highlight unique circumstances and challenges for obtaining site control on certain public lands and other regulatory issues that may affect an

[1117] Avangrid Initial Comments at 19; Clean Energy Associations Initial Comments at 32; CREA and NewSun Initial Comments at 55; Interwest Energy Alliance Reply Comments at 13.

[1118] Avangrid Initial Comments at 19.

[1119] Pacific Northwest Utilities Initial Comments at 3.

[1120] PPL Initial Comments at 16; Tri-State Initial Comments at 14; Xcel Initial Comments at 31.

interconnection customer's ability to demonstrate site control under the NOPR definition.[1121]

556. Several commenters argue that the Commission should provide flexibility to allow transmission providers to establish site control requirements for generating facilities sited on federal and public land.[1122] Shell notes that securing site control can often be complicated by fast-changing local, county, and state regulations, and encourages the Commission to provide sufficient flexibility to enable transmission providers to make accommodations for local site control challenges.[1123]

557. Some commenters provide recommendations on how the Commission could clarify what may constitute a sufficient demonstration of site control for generating facilities being developed on land owned or controlled by a government entity.[1124] Pattern Energy argues that interconnection customers proposing to develop generating

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[1121] Clean Energy Associations Initial Comments at 33-34; CREA and NewSun Reply Comments at 47-49; Dominion Initial Comments at 31; ENGIE Initial Comments at 4; Hydropower Commenters Initial Comments at 14-18, 24-25; Idaho Power Initial Comments at 6-7; NV Energy Initial Comments at 15-16; Ørsted Initial Comments at 12; OSPA Initial Comments at 16-18; rPlus Initial Comments at 2-3.

[1122] Dominion Initial Comments at 32; Indicated PJM TOs Initial Comments at 26; Pacific Northwest Utilities Initial Comments at 3; PJM Initial Comments at 31; Shell Initial Comments at 23.

[1123] Shell Initial Comments at 23.

[1124] *Id.* at 22-23; CREA and NewSun Reply Comments at 50; Equinor Reply Comments at 4; Hydropower Commenters Initial Comments at 15-18; Idaho Power Initial Comments at 7; Indicated PJM TOs Reply Comments at 31; Ørsted Initial Comments at 12-13; Ørsted Reply Comments at 2, 4-5; OSPA Initial Comments at 18; Pattern Energy Initial Comments at 30; rPlus Initial Comments at 3-4.

facilities on land owned or managed by state, federal, or Tribal government entities should be required to provide evidence that they submitted any required applications to the relevant government entity or entities in order to advance the development of their proposed generating facility. Pattern Energy states that such an interconnection request should provide for an exclusive right to advance the development of a generating facility, provided that the relevant government entity or entities allow for such an exclusive right.[1125]

558. PJM notes that the proposed site control requirements that PJM included in its interconnection queue reform filing with the Commission provide some leeway for generating facilities constructed on federal or state lands or water, such as offshore wind projects.[1126] Alternatively, Dominion requests that the Commission clarify that the deposit in lieu of site control exception would apply to offshore wind projects, in addition to other proposed generating facilities subject to similar government control that may prevent timely demonstration of site control.[1127]

559. Several commenters note that certain interconnection customers with generating facilities and interconnection facilities on land controlled by the Bureau of Land Management (BLM) face extended time frames for obtaining firm site control.[1128] For

[1125] Pattern Energy Initial Comments at 30.

[1126] PJM Initial Comments at 29-30, 32; *see PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162 at PP 83-105.

[1127] Dominion Initial Comments at 32.

[1128] CREA and NewSun Reply Comments at 49; Idaho Power Initial Comments at

example, NV Energy states that the BLM permitting process can take between 18 months and 5 years.[1129] Idaho Power states that BLM goes through various stages of review, but there is no specific stage that is indicative of an interconnection customer's request having firm site control until the permit is in hand, which can take up to three years to obtain.[1130] Idaho Power states that, currently, interconnection customers with generating facilities on BLM lands typically reference the section of the site control definition that allows for "an exclusivity or other business relationship between interconnection customer and the entity having the right to sell, lease or grant interconnection customer the right to possess or occupy a site for such purpose."[1131] Idaho Power argues that generating facilities on land managed by BLM should have the same site control requirements as all other generating facilities, but that they would support an expanded and/or clarified definition of site control to capture the limitations of these generating facilities. Idaho Power states that, for example, site control evidence may include evidence that the necessary application has been received by the agency, is in process, and the agency has indicated the generating facility is permittable.

560. NV Energy proposes that the deposit in lieu of site control be used for lands that are federally managed, and that those deposits be held until the decision record, record of

6; NV Energy Initial Comments at 16.

[1129] NV Energy Initial Comments at 16.

[1130] Idaho Power Initial Comments at 6-7.

[1131] *Id.*

decision, notice to proceed, or right-of-way grant is issued for a generating facility, which NV Energy notes may not be until after the facilities study due to timing of the BLM process.[1132] To ensure the generating facility is progressing in the BLM process, NV Energy also proposes that the interconnection customer be required to submit with its interconnection request a schedule of the land rights and permitting as well as documentation from BLM that the draft environmental assessment or draft environmental impact statement is expected to be completed by issuance of the system impact study. NV Energy also proposes that interconnection customers be required to provide the administrative draft environmental assessment or draft environmental impact statement to the transmission provider for review and comment once BLM has issued it to ensure its interconnection facilities are included in the right-of-way that BLM will issue.

561. CREA and NewSun encourage the Commission to modify its proposed site control requirements, such that an interconnection customer developing generating facilities on public lands is allowed to proceed with the interconnection process if it can demonstrate that the relevant public agency has received and has agreed to process the necessary permits to develop the interconnection customer's proposed generating facility.[1133]

562. For generating facilities on Bureau of Reclamation lands, Hydropower Commenters argue that a lease of power privilege should be considered a sufficient

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[1132] NV Energy Initial Comments at 17.

[1133] CREA and NewSun Reply Comments at 50.

demonstration of site control.[1134] Additionally, Hydropower Commenters note that generating facilities under a certain size can obtain an exemption from Commission licensing requirements, and they argue that an exemption from licensing should also be considered a sufficient demonstration of site control. Similarly, Hydropower Commenters argue that developers of pumped storage projects on U.S. Forest Service or BLM lands should not be required to complete the required Federal Land Policy and Management Act process before they can be considered to have demonstrated sufficient evidence of site control.[1135] Hydropower Commenters contend that such generating facilities should be allowed to demonstrate site control by submitting evidence that they have a permit application pending with U.S. Forest Service or BLM.

563. Some commenters argue that the 100% site control requirement should not apply to generating facilities being developed on Tribal lands.[1136] OSPA claims that development on Tribal land is more challenging than other kinds of development because Tribes have three different classes of land that have different ownership structures and regulatory restrictions, including "Trust" land, which is held by the federal government on behalf of Tribes and regulated by the Bureau of Indian Affairs.[1137] OSPA notes that Tribes' Reservations are often "checker-boarded" with the three different classes of land,

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[1134] Hydropower Commenters Initial Comments at 16-17.

[1135] *Id.* at 25.

[1136] OSPA Initial Comments at 16; rPlus Initial Comments at 2.

[1137] OSPA Initial Comments at 17.

and that large wind generating facilities will necessarily be sited on all three classes of land. OSPA argues that securing Bureau of Indian Affairs regulatory approvals can take years and that the ownership structure of "Allotted" lands can make it even difficult to expediently obtain consent from all owners to lease certain tracts, which is required as part of the Bureau of Indian Affairs process.[1138]

564. OSPA proposes that, for Tribes and Tribal Energy Development Organizations, the Commission clarify that interconnection queue positions may be secured if the Tribe has signed a lease, even if the Bureau of Indian Affairs has not issued a final approval.[1139] Similarly, rPlus recommends that the filing of a valid preliminary permit application with the Commission satisfy the site control requirement for a pumped storage project and for generating facilities on Tribal lands.[1140] rPlus notes that suitable pumped storage sites are limited in availability and are increasingly located on public or Tribal lands, which involve significant environmental review. rPlus notes that pumped storage projects located on federal and Tribal lands generally cannot achieve full site control until federal environmental reviews are complete and the Commission issues a license. For circumstances where a pumped storage project does not require a Commission license,

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[1138] *Id.* at 17-18.

[1139] *Id.* at 18.

[1140] rPlus Initial Comments at 2-3.

rPlus requests that the site control requirement be only 50% of the land needed for the core generating facility.[1141]

565. Several commenters state that the proposed site control requirements may present challenges for offshore wind projects, which face extensive permitting timelines.[1142] Clean Energy Associations argue that the formal issuance of a public lease often requires multiple preliminary stages and major financial commitments from interconnection customers and that requiring a lease prior to entering the interconnection queue would unduly delay generating facilities on public lands.[1143] Ørsted and Clean Energy Associations further explain that the permitting process for an offshore wind farm often involves multiple federal and state agencies and runs concurrently with the interconnection process. Ørsted and Clean Energy Associations note that the permitting process can lead to changes in the generating facility layout within a lease area, routing of offshore cables, siting of onshore cable landing, routing of onshore cables, and siting of the interconnection switchyard.[1144]

566. Shell, Dominion, and CREA and NewSun argue that the high cost of market entry for offshore wind projects is a substantial financial commitment and that such generating

[1141] *Id.* at 4.

[1142] Clean Energy Associations Initial Comments at 33; CREA and NewSun Reply Comments at 48; Dominion Initial Comments at 31; Ørsted Initial Comments at 12.

[1143] Clean Energy Associations Initial Comments at 33.

[1144] *Id.* at 33-34; Ørsted Initial Comments at 12.

facilities are by their very nature not speculative.[1145] Shell argues that offshore wind generation should be able to demonstrate site control by showing evidence of commitments to purchase offshore lease areas from BOEM, as commitments often demand hundreds of millions of dollars.[1146]

567. CREA and NewSun contend that the site control requirements in the NOPR would require an offshore developer to win a competitive solicitation or obtain a term sheet from an off-taker before entering the interconnection queue, which at best will add years of delay to developing these generating facilities and at worst will kill the proposals outright due to a lack of information on interconnection feasibility and cost.[1147]

568. MISO notes that it has not interpreted its tariff to mean that a BOEM-administered Wind Energy Area auction that an offshore wind interconnection customer can participate in, but which will occur after the close of an application window, is a regulatory restriction.[1148] MISO is concerned that broadening the regulatory restriction interpretation to allow for offshore wind to submit an interconnection request in such instances would enable speculative interconnection requests, which will result in withdrawals, restudies, uncertainty, and study delays. MISO states that interconnection

[1145] CREA and NewSun Reply Comments at 48; Dominion Initial Comments at 31; Shell Initial Comments at 22.

[1146] Shell Initial Comments at 22.

[1147] CREA and NewSun Reply Comments at 48.

[1148] MISO Initial Comments at 55.

customers that seek to develop a generating facility on government owned lands that are awarded to the winner of an auction, and interconnection customers that seek to develop a generating facility on private land, are held to the same standard in the MISO process.

569. Some commenters request that "regulatory limitations" be more clearly defined.[1149] CAISO expresses concern that, absent clarification, the regulatory limitation provision will leave transmission provider staff as adjudicators of whether obtaining site control is possible for each proposed generating facility, and interconnection staff are not experts on real property law or public permitting requirements.[1150] CAISO and Indicated PJM TOs argue that without further clarification, the regulatory limitation provision may be interpreted too broadly and interconnection customers could argue site control was impossible where it was simply impractical or expensive.[1151] CAISO suggests, as an example, that the Commission could limit "regulatory limitations" only to apply to interconnection customers sited in offshore areas, public lands, and Tribal lands.[1152]

570. Several parties support the NOPR proposal to allow interconnection customers with regulatory limitations to submit a deposit in lieu of site control.[1153] For projects on

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[1149] APS Initial Comments at 14; CAISO Initial Comments at 17; EEI Initial Comments at 7-8; NYISO Initial Comments at 22; PG&E Reply Comments at 2; Indicated PJM TOs Initial Comments at 26-27; Shell Reply Comments at 24.

[1150] CAISO Initial Comments at 17 & n.29.

[1151] *Id.* at 17; Indicated PJM TOs Initial Comments at 26-27, 31.

[1152] CAISO Initial Comments at 17.

[1153] APPA-LPPC Initial Comments at 3-4; Cypress Creek Initial Comments at 22; SEIA Initial Comments at 15-16; NY Commission and NYSERDA Initial Comments at

government lands, Indicated PJM TOs argue that the interconnection customer should be allowed to enter and remain in the interconnection queue, with a deposit in lieu of site control, if they identify the steps needed to achieve site control and show how they are exercising due diligence to obtain a final government determination.[1154] Indicated PJM TOs argue that the regulatory limitations exception should be limited to just government lands.

571. MISO supports such an option specifically when the interconnection customer is prevented from obtaining site control by a regulatory restriction that the passage of time itself will not cure (e.g., while participating in an auction that occurs after the interconnection request deadline can be cured by time, a requirement to obtain an LGIA to participate in an auction cannot be cured by time).[1155]

572. Tri-State suggests modifying section 3.4.[1]2 of the *pro forma* LGIP so that the site control for state or federally controlled land must still be fully attained at the time of LGIA execution.[1156] For example, Tri-State states that in Colorado, a state land planning lease (which does not meet the Commission's proposed definition of site control) could be used with a financial deposit during the cluster study process, and a state land

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[1154] Indicated PJM TOs Reply Comments at 31.

[1155] MISO Initial Comments at 57.

[1156] Tri-State Initial Comments at 13, 27.

production lease (which does meet the Commission's proposed definition of site control) would be needed prior to LGIA execution.[1157]

573. APPA-LPPC argue that, if the NOPR proposal is adopted, at a minimum, the interconnection customer should be required to provide an affidavit from a company officer, a detailed explanation, and documentation justifying the proposed regulatory limitation exception and to demonstrate 100% site control as soon as possible after the generator interconnection request is submitted, and certainly prior to the facilities study stage, as the NOPR proposes.[1158] PPL contends that, while additional flexibility for interconnection customers that face regulatory limitation may be appropriate in the early stages of review, the Commission should require that full site control be demonstrated before proceeding to an LGIA.[1159]

574. A number of commenters oppose the NOPR's proposed option to allow deposits in lieu of site control where federal or state regulatory limitations prohibit the interconnection customer from obtaining site control.[1160] Idaho Power argues that any allowance of a deposit must be accompanied by some evidence of achieving site

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[1157] *Id.* at 13.

[1158] APPA-LPPC Initial Comments at 20.

[1159] PPL Initial Comments at 16.

[1160] APPA-LPPC Initial Comments at 19; APS Initial Comments at 14; Bonneville Initial Comments at 11; Idaho Power Initial Comments at 7; Indicated PJM TOs Initial Comments at 11; Indicated PJM TOs Reply Comments at 31; PJM Initial Comments at 26; PPL Initial Comments at 16; Southern Initial Comments at 9; SPP Initial Comments at 10; Xcel Initial Comments at 30, 32.

control.[1161] APS asserts that speculative interconnection requests do not necessarily have financial limitations and extra deposits would not act as the same deterrent as requiring 100% site control; therefore, APS requests that the Commission not allow an exception for regulatory restrictions.[1162]

575. OSPA argues that requiring interconnection customers that face regulatory barriers to submit any deposits, including deposits in lieu of site control, will create insuperable barriers to renewable energy development by Native American Tribes and Tribal Energy Development Organizations on Tribal lands,[1163] stating that Tribes have limited access to capital and face other challenges that large developers do not share.[1164]

576. A few commenters support the proposed amounts for the deposit in lieu of site control.[1165] MISO agrees that the proposed deposit thresholds are sufficient, noting that the amount of the deposits under MISO's tariff are the same amounts the Commission proposed in the NOPR.[1166] Tri-State contends that the proposed deposit amounts would

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[1161] Idaho Power Initial Comments at 7.

[1162] APS Initial Comments at 14.

[1163] OSPA Initial Comments at 18.

[1164] OSPA Reply Comments at 12.

[1165] MISO Initial Comments at 57; NV Energy Initial Comments at 15; Tri-State Initial Comments at 13.

[1166] MISO Initial Comments at 57.

be sufficient to ensure advanced-stage interconnection requests are able to continue to move toward interconnection.[1167]

577. Several parties support a deposit in lieu of site control high enough to deter speculative interconnection requests that are unlikely to achieve site control.[1168] Avangrid argues that any deposit in lieu of site control should be proportionate to the size of the interconnection request, and "reflect collateral" while an interconnection customer works through site control agreements.[1169] Eversource similarly argues that the Commission should set the deposit so that the interconnection customer fully internalizes the risk of failing to obtain site control.[1170] Tri-State also argues that the deposit should not apply to interconnection study costs.[1171]

578. Some commenters provide alternative suggestions for the deposit in lieu of site control amounts.[1172] Longroad Energy argues that the Commission should consider requiring that such deposits be set as a multiple of the interconnection study deposit (such as three times the deposit amount), rather than as a dollar amount per MW of generating

[1167] Tri-State Initial Comments at 13.

[1168] *Id.* at 14; Avangrid Initial Comments at 19; ENGIE Initial Comments at 4; GSCE Initial Comments at 7; NYTOs Initial Comments at 19; Pacific Northwest Utilities Initial Comments at 3-4.

[1169] Avangrid Initial Comments at 19.

[1170] Eversource Initial Comments at 17.

[1171] Tri-State Initial Comments at 14.

[1172] Eversource Initial Comments at 17; Longroad Energy Initial Comments at 12; NYTOs Initial Comments at 19.

facility size, as proposed in the NOPR.[1173] NYTOs argue that the MW capacity of a generating facility is not necessarily relevant to determining the appropriate deposit requirement and that deposits should be more closely tied to the generating facility's potential impact on the interconnection process.[1174]

579. A number of entities argue that any deposits in lieu of site control should be non-refundable.[1175] Avangrid suggests that the deposit be non-refundable to avoid gaming by prospective interconnection customers.[1176] National Grid argues that absent circumstances outside the control of the interconnection customer, any deposit should be non-refundable, and any security should be able to be drawn upon in the event the interconnection customer withdraws or fails to demonstrate site control at the required time.[1177] National Grid contends that if the Commission intends to permit refunds or returns of a deposit in lieu of site control, such deposits should be provided only after deducting the actual costs and fees, e.g., escrow account initiation and maintenance fees, incurred by the transmission provider or RTOs/ISOs prior to the time of the withdrawal

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[1173] Longroad Energy Initial Comments at 12; Longroad Energy Reply Comments at 18.

[1174] NYTOs Initial Comments at 19.

[1175] Avangrid Initial Comments at 19; EEI Initial Comments at 8; Longroad Energy Initial Comments at 12; National Grid Initial Comments at 23; NYTOs Initial Comments at 19.

[1176] Avangrid Initial Comments at 19.

[1177] National Grid Initial Comments at 23-24.

request or the demonstration of site control. National Grid also requests that the Commission clarify that withdrawal penalties are separate and may be deducted from the deposit amount.

580. Similarly, Longroad Energy suggests that to ensure that the proper incentives exist, the Commission may wish to evaluate if a security deposit in lieu of site control should become non-refundable if an interconnection customer withdraws at any point in the interconnection process or fails to achieve commercial operation.[1178] EEI argues that the Commission can further reduce potential risks by making deposits non-refundable, or if the Commission declines to do so, it should ensure that withdrawal penalties are significant enough to discourage speculative interconnection requests.[1179] On the other hand, NYTOs argue that regions should have the flexibility to determine whether, under certain circumstances, deposits should become fully non-refundable.[1180]

581. Xcel argues that in addition to requiring a deposit, interconnection customers facing regulatory limitations should be required to provide status updates to the transmission provider, and there should be sufficient penalties to ensure interconnection customers provide accurate information on the status of regulatory proceedings.[1181] Xcel contends that, if regulatory limitations prohibit an interconnection customer from

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[1178] Longroad Energy Initial Comments at 12.

[1179] EEI Initial Comments at 8.

[1180] NYTOs Initial Comments at 19.

[1181] Xcel Initial Comments at 30-31.

obtaining site control, transmission providers should be allowed to propose constructs that facilitate interconnection, including the ultimate achievement of site control.

(c) Miscellaneous

582. Public Interest Organizations argue that it is unreasonable that the *pro forma* LGIP allows interconnection customers to propose a decrease to the generating facility's output of up to 60% without losing queue position while also requiring a demonstration of 100% site control upon entering the interconnection queue.[1182] Public Interest Organizations also argue that the NOPR proposal to require interconnection customers to remedy any change in site control within 10 days or have their interconnection request withdrawn is unreasonable. In addition, Public Interest Organizations argue that it is unduly discriminatory to allow interconnection customers proposing a thermal project to keep their queue position by downsizing the generating facility's turbines but not allow interconnection customers proposing wind generating facilities to keep their queue position if they lose part of a lease. Public Interest Organizations argue that the cure period should be long enough to allow for routine events that affect site control, such as the death of a landowner or the change of ownership at a commercial facility hosting a proposed generating facility.

iii. Commission Determination

583. As discussed herein, we adopt in part and modify in part the NOPR proposal to revise sections 1, 3.4.2, 7.5, 8.1, and 11.3 of the *pro forma* LGIP and Appendix B of the

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[1182] Public Interest Organizations Initial Comments at 27-28.

pro forma LGIA to add more stringency to the site control requirements and to help prevent speculative interconnection requests from entering the interconnection queue. We believe that, taken together, these reforms will help ensure that commercially viable interconnection requests with demonstrated site control or with demonstrated regulatory limitations will be able to enter the interconnection queue, thereby reducing the negative impacts of speculative interconnection requests.

(a) <u>Definition and Reasonable Evidence of Site Control</u>

584. We adopt the NOPR proposal to revise the definition of site control in section 1 of the *pro forma* LGIP with several modifications. As modified, the definition states that site control may be demonstrated by documentation establishing: "(1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size to construct and operate the Generating Facility; (2) an option to purchase or acquire a leasehold site of sufficient size to construct and operate the Generating Facility; or (3) any other documentation that clearly demonstrates the right of Interconnection Customer to exclusively occupy a site of sufficient size to construct and operate the Generating Facility." Additionally, we agree with commenters' observations[1183] that subpart (3) of the *pro forma* LGIP definition of site control proposed in the NOPR, which stated "site of sufficient size to construct and operate the Generating Facility," was duplicative; therefore, we modify the NOPR proposal to delete this subpart and provide clarification that all three remaining,

[1183] *See* Enel Initial Comments at 82; Southern Initial Comments at 34-35.

enumerated options to demonstrate site control require control of a site of sufficient size to construct and operate the generating facility or multiple generating facilities on a shared site.

585. To prevent multiple interconnection customers from leasing the same site in order to remain in the interconnection queue, we adopt the NOPR's proposed revisions to the *pro forma* LGIP that require an interconnection customer to demonstrate the exclusive land right to develop, construct, operate, and maintain its generating facility or, where facilities are co-located, to demonstrate a shared land use right to develop, construct, operate, and maintain co-located facilities. We further clarify that the right to "exclusively" occupy the site to develop, construct, operate, or maintain a generating facility means both that the right belongs solely to the interconnection customer (no other entity shares the right to use the site for those purposes), as well as that the right is solely for purposes of a single interconnection request. We find that an interconnection customer securing the exclusive land right necessary to construct its proposed generating facility (or for co-located generating facilities, demonstration of shared land use) is sufficient evidence of the interconnection customer's commitment to construct the generating facility.

586. We also modify section 3.4.2 of the *pro forma* LGIP to provide that site control for a generating facility that is co-located with one or more generating facilities on the same site and behind the same point of interconnection must be demonstrated by a contract or other agreement that allows for shared land use for all generating facilities that are co-located that meet the provisions of the site control definition. We clarify that

interconnection customers are prohibited from submitting evidence of site control that uses the same land for multiple interconnection requests, unless the site is large enough to host multiple generating facilities. We note that section 3.4.2 of the *pro forma* LGIP that we adopt in this final rule permits shared land use for co-located generating facilities on the same site and behind the same point of interconnection, and we clarify below that transmission providers have flexibility to establish appropriate technology-specific acreage requirements for generating facilities.[1184] Permitting multiple interconnection requests to use the same land to demonstrate exclusive site control would inherently result in at least one commercially non-viable interconnection request entering the interconnection queue and thus would be insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. We also clarify that the interconnection customer is required to meet the technology-specific acreage requirement for its generating facility that is publicly posted by the transmission provider at the time it submits its interconnection request.

587. Likewise, in response to Enel, we clarify that the term "exclusive land rights" in the definition of site control applies only to the exclusivity required to develop, construct, operate, and maintain the interconnection customer's proposed generating facility; the

[1184] This is consistent with the practice that several transmission providers currently follow. *See Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,173 at P 48; *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114 at P 48; *PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162 at P 102.

term "exclusive land rights" does not restrict multi-use applications of the site in addition to its use for the generating facility, such as agriculture, ranching, etc.[1185] Similarly, in response to Cypress Creek, we clarify that a land right does not involve zoning approval.

588. In response to commenters,[1186] we further clarify that the adopted definition of site control permits an interconnection customer to demonstrate site control with lease options, instead of executed leases, provided that the interconnection customer is the exclusive holder of such a lease option(s). The adopted definition explicitly provides for such a lease option, by including the phrase, "an option to purchase or acquire a leasehold site." However, evidence of active negotiations for a lease is not a sufficient demonstration of site control at any time during the interconnection process. Allowing active negotiations for a lease to serve as a demonstration of site control, as some commenters suggest,[1187] would allow speculative, commercially non-viable interconnection requests to proceed through the interconnection queue, which would be inconsistent with ensuring that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. Likewise, with respect to NRECA's request,[1188] we clarify that this final rule permits leases and

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[1185] *See* Enel Initial Comments at 42.

[1186] Omaha Public Power Initial Comments at 7; SoCal Edison Initial Comments at 6.

[1187] EPSA Initial Comments at 8; Interwest Reply Comments at 13.

[1188] NRECA Initial Comments at 27.

lease options as sufficient evidence of site control as discussed above, and transmission providers have discretion to evaluate the content of such leases and lease options and any conditions contained therein to determine whether they sufficiently demonstrate site control.

589. Several commenters seek clarification as to whether the proposed *pro forma* LGIP definition of site control would allow certain types of generating facilities developed on lands owned or controlled by a government entity to demonstrate site control. We agree with commenters that offshore wind interconnection customers must make a substantial financial commitment to win a competitive auction and secure a lease from BOEM, and such generating facilities that have secured a lease agreement are not speculative.[1189] We therefore clarify that a lease agreement with BOEM to pursue development of an offshore wind generating facility can serve as a sufficient demonstration of site control under the site control definition adopted in this final rule. This clarification is consistent with our finding above that a variety of lease options satisfy the site control requirement. In response to MISO's concerns about allowing multiple offshore wind interconnection customers to submit an interconnection request for the same "Wind Energy Area" before it has been auctioned by BOEM, we find that the *pro forma* LGIP site control definition that we adopt herein appropriately limits such potentially speculative interconnection

[1189] CREA and NewSun Reply Comments at 48; Dominion Initial Comments at 31; Shell Initial Comments at 22.

requests by requiring offshore wind interconnection customers to provide evidence of an exclusive right to develop a lease area to satisfy the site control requirements.

590. With respect to OSPA's concerns regarding the challenges of demonstrating site control on Tribal lands due to the nature of land ownership on Reservations and the need for the Bureau of Indian Affairs to approve certain leases, we clarify that under the site control definition, interconnection customers developing generating facilities on Tribal lands can demonstrate site control with a signed lease agreement with the applicable Tribe-owner.[1190] As discussed below in Section III.A.6.b.iii.b, an interconnection customer with a demonstrated regulatory limitation, including those associated with obtaining a lease on Tribal lands, may submit a deposit in lieu of site control.

591. Similarly, in response to commenters' concerns about demonstrating site control for hydropower projects on sites owned or controlled by a government entity, we clarify that certain documentation can be used to demonstrate site control under the *pro forma* LGIP definition of site control. For interconnection customers developing generating facilities at non-powered dams, we clarify that a FERC license[1191] can serve as a demonstration of site control under subpart (3). However, we also clarify that neither a Memorandum of Agreement with the U.S. Army Corps of Engineers regarding a

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[1190] OSPA Initial Comments at 17-18.

[1191] A FERC license provides the licensee with the power of eminent domain to secure property rights needed to construct and operate the project. *See* 16 U.S.C. 814. While a FERC license does not explicitly convey an exclusive right to develop a project, the Commission does not approve more than one license for the same site.

proposed hydropower project at a U.S. Army Corps of Engineers dam nor a preliminary permit for a pumped storage project or other hydropower generating facility to be located on Tribal lands would be sufficient to demonstrate site control because we do not have enough information in this record to determine that such documentation provides sufficient evidence of the interconnection customer's exclusive right to occupy a site of sufficient size to construct and operate a generating facility.

592. For hydropower projects that are not subject to the Commission's hydropower permitting jurisdiction, such as projects on Bureau of Reclamation lands, we clarify that a lease of power privilege can serve as a demonstration of site control under the site control definition. Finally, for hydropower projects that are small enough to be exempted from FERC licensing requirements, Hydropower Commenters explain that an exemption from FERC licensing provides an exclusive right to the recipient to develop a project at the site and the exemption is issued in perpetuity.[1192] Because such an exemption includes an exclusive right to develop, we clarify that providing a written statement as evidence of an exemption from licensing under the FPA can serve as a demonstration of site control under subpart (3) of the site control definition.

593. We note NV Energy's explanation that its previous efforts to allow interconnection customers to demonstrate site control by showing a draft preliminary plan of development, one of the earlier required documents in the BLM permitting process, have led to speculative interconnection requests that slow down the

[1192] Hydropower Commenters Initial Comments at 17.

interconnection process.[1193] We agree, and we therefore decline to adopt commenters' proposal to modify the proposed *pro forma* LGIP definition of site control to allow interconnection customers to demonstrate site control by providing documentation indicating that they are pursuing the necessary permits with the appropriate government entity or entities.[1194] As with our finding that active negotiations for lease agreements are not sufficient to demonstrate site control, discussed above, we find that such an expansion of the site control definition could weaken the site control requirements included in the *pro forma* LGIP and could undermine the effectiveness of this reform in helping to prevent speculative interconnection requests.

(b) Site Control Demonstration and Deposits in Lieu of Site Control

594. We adopt the NOPR proposal, with modification, to revise section 3.4.2 of the *pro forma* LGIP to require interconnection customers to demonstrate site control at the time of submission of the interconnection request. However, we modify the proposal and require interconnection customers to provide evidence of 90% site control for the generating facility at the time of submission of the interconnection request and, pursuant to revised sections 8.1 and 11.3 of the *pro forma* LGIP, provide evidence of 100% site control for the generating facility at the time of execution of the facilities study agreement and when executing, or requesting the unexecuted filing of, the LGIA.

[1193] NV Energy Initial Comments at 15-16.

[1194] *See* CREA and NewSun Reply Comments at 50; Pattern Energy Initial Comments at 30.

595. We decline to adopt the NOPR proposal to require technology-specific acreages to be listed in the transmission provider's tariff. As discussed below, instead, we require transmission providers to establish acreage requirements for each generating facility technology type and to publicly post these acreage requirements. We adopt the following aspects of the NOPR proposal to revise sections 3.4.2 and 11.3 of the *pro forma* LGIP to: (1) eliminate the option to provide a deposit in lieu of site control demonstration except in limited circumstances where an interconnection customer demonstrates a regulatory limitation to obtaining site control, as discussed below, and eliminate the option to post $250,000 of non-refundable security in lieu of site control at LGIA execution; and (2) require that interconnection customers that could not demonstrate the requisite level of site control at the relevant milestone of the interconnection process (i.e., 90% for the cluster study and cluster restudy, and 100% for the interconnection facilities study and when executing, or requesting the unexecuted filing of, the LGIA) would have their interconnection request deemed withdrawn and could be subject to withdrawal penalties under certain circumstances, as discussed below.

596. We adopt the NOPR proposal to revise sections 3.4.2, 7.5 and 8.1 of the *pro forma* LGIP such that, after notifying the transmission provider of any change to the interconnection customer's site control demonstration, the transmission provider must give the interconnection customer 10 business days to demonstrate satisfaction with the applicable requirement. We find the adopted approach to require 90% site control at the time of the interconnection request and 100% site control at the time of the facilities study and when executing, or requesting the unexecuted filing of, the LGIA appropriately

balances the concerns identified in the record. In particular, we find that it will provide sufficiently stringent site control requirements to help prevent interconnection customers from submitting interconnection requests for speculative, commercially non-viable proposed generating facilities, while accommodating development challenges faced by interconnection customers that may otherwise present unjust and unreasonable barriers to entering the interconnection queue. We believe that this approach appropriately recognizes that issues often arise in developing a generating facility, such that requiring a demonstration of 90% site control at the time of the interconnection request, rather than 100%, provides valuable flexibility for interconnection customers with viable prospective generating facilities to resolve those issues and continue through the interconnection process.

597. We are persuaded by commenters that contend that there are significant benefits to allowing interconnection customers to enter the cluster study process and potentially use the interconnection study results to better understand their generating facility configuration before obtaining 100% site control. We agree with commenters that allowing less than 100% site control at the interconnection request stage would provide interconnection customers flexibility to address the results of interconnection studies or other regulatory processes[1195] and afford flexibility for interconnection customers that are still actively negotiating with landowners close to the deadline for a cluster request

[1195] *See* CREA and NewSun Initial Comments at 55; SEIA Initial Comments at 14-15.

window.[1196] Establishing a requirement for 90% site control at the time of an interconnection request allows an interconnection request to be submitted even if a few parcels of land are still in negotiation or where a different site configuration arises based on the scoping meeting with the transmission provider. Moreover, the adopted approach provides flexibility for interconnection customers to sign certain leases for particularly challenging parcels at a later point in time, reducing the exposure to risk of expiration of those leases.[1197] Additionally, we agree with commenters that shifting the 100% site control requirement until the execution of a facilities study agreement allows the interconnection customer to put less money at risk for obtaining particularly challenging land rights and to obtain a more meaningful understanding of what upgrade costs its generating facility may be assigned, for instance, from the cluster study report that is provided before the execution of the facilities study agreement.[1198]

598. At the same time, we believe that the approach adopted in this final rule, along with the other reforms adopted herein, is sufficiently stringent to help prevent speculative, commercially non-viable proposed generating facilities from entering and continuing through the interconnection queue. As an initial matter, we establish a more stringent requirement for site control at the time of submission of an interconnection

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[1196] *See* Pine Gate Initial Comments at 23-24.

[1197] Enel Initial Comments at 40.

[1198] AEE Initial Comments at 18; Clean Energy Associations Initial Comments at 31-32; CREA and NewSun Initial Comments at 55; Cypress Creek Initial Comments at 22; SEIA Initial Comments at 15; Shell Reply Comments at 23-24.

request than required by the *pro forma* LGIP prior to this final rule. In particular, obtaining nearly all of the land rights necessary to develop a proposed generating facility prior to submitting the interconnection request entails a significant commitment, both financial and in terms of the time and resources required to negotiate with landowners. Moreover, the 100% site control requirement at the time of the execution of the facilities study agreement adds further stringency to ensure generating facilities that proceed through the interconnection queue are the most likely to be commercially viable.

599. We agree with commenters that requiring 100% site control at the time of submission of an interconnection request may not be compatible with the project development cycle,[1199] which includes stringent permitting requirements, and may disadvantage certain interconnection customers despite there being a path to full site control and commercial readiness.[1200] Further, requiring 100% site control at submission of the interconnection request would not allow for minor revisions to the generating facility plan if, upon meeting with the transmission provider at the scoping meeting, such revisions would facilitate an improved generating facility design. This could present a barrier to entry for interconnection customers with viable proposed generating facilities.

[1199] AEE Initial Comments at 17; CREA and NewSun Initial Comments at 54; Clean Energy Associations Initial Comments at 31; Cypress Creek Initial Comments at 22; EPSA Initial Comments at 8; NextEra Initial Comments at 21; R Street Initial Comments at 8.

[1200] AEE Initial Comments at 17.

600. We decline to adopt commenters' suggestions that transmission providers be allowed to confirm site control throughout the interconnection process.[1201] The adopted site control requirements require site control demonstrations at three specific points in the interconnection process—submission of the interconnection request; at the time of execution of the facilities study agreement; and when executing, or requesting the unexecuted filing of, an LGIA. We find that these points are sufficient to help prevent interconnection customers with commercially non-viable interconnection requests from entering and proceeding through the interconnection queue.

601. With respect to eliminating the option for any interconnection customer to submit a deposit in lieu of site control, except in limited circumstances where an interconnection customer demonstrates a regulatory limitation, we find that, because a deposit in lieu of site control does not demonstrate that an interconnection customer has the exclusive right to develop a site, it does not indicate that an interconnection customer is ready to proceed with construction and commercial operation of the generating facility. As a result, we believe that allowing deposits in lieu of site control for all interconnection customers, as requested by some commenters, would not help to prevent speculative, commercially non-viable interconnection requests from entering the interconnection queue. Thus, we decline to include such an option in the *pro forma* LGIP.

602. We are persuaded by commenters that requiring transmission providers to publicly maintain per MW acreage requirements for each generating facility technology type is

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[1201] *See* Indicated PJM TOs Initial Comments at 26; MISO Initial Comments at 53.

necessary to afford adequate transparency and certainty to interconnection customers. At the same time, we do not believe that such acreage requirements must be contained within transmission providers' tariffs; rather, we find that, consistent with the rule of reason, transmission providers may choose to maintain acreage requirements in their business practice manuals or may otherwise post them on a publicly accessible website. We find that acreage requirements are properly classified as implementation details that do not significantly affect rates, terms, and conditions of service,[1202] and we therefore do not require their inclusion in tariffs. This is consistent with previous Commission orders approving transmission providers' proposals to specify technology-specific acreage requirements for site control in their business practice manuals.[1203] This will also afford transmission providers more flexibility in updating acreage requirements to account for technological advancements without being required to make FPA section 205 filings each time they seek to modify the acreage requirements. On the other hand, to give the interconnection customer certainty, as noted above, we clarify that the interconnection customer is required to meet the technology-specific acreage requirement for its generating facility publicly posted by the transmission provider at the time it submits its interconnection request.

[1202] *See, e.g.*, *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 at PP 105-114.

[1203] *See Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,173 at P 48 (finding MISO's proposal to place resource-specific acreage requirements in its business practice manuals to be appropriate because "these requirements include technical calculations that may require updates from time to time"); *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114 at P 48; *PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162 at P 102.

603. To provide clarity for interconnection customers and transmission providers, we modify the *pro forma* LGIP definition of "Generating Facility" to replace "device" with "device(s)" to clarify that this definition includes hybrid generating facilities.[1204] We believe this clarification is necessary to ensure that hybrid generating facilities have the same rights and responsibilities as other types of generating facilities under the *pro forma* LGIP and *pro forma* LGIA. In response to commenters and consistent with the modified definition of "Generating Facility," we clarify that the transmission providers' per MW acreage requirements for each generating facility technology-type must include specific requirements for hybrid generating facilities. We also clarify that generating facilities that are co-located on the same site and behind the same point of interconnection are subject to the technology-specific acreage requirements based on the generating facilities' technology-type.

604. In response to requests for clarification as to whether the site control demonstration at the time of submission of the interconnection request applies to interconnection facilities as well as generating facilities, we clarify that the site control demonstration requirements apply only to the land needed for the generating facility. In the NOPR, the Commission did not propose site control requirements for interconnection

[1204] A hybrid generating facility is a generating facility composed of more than one device of different technology types for the production and/or storage for later injection of electricity that are located on the same site and are operated and dispatched as a single integrated generating facility.

facilities.[1205] Based on this clarification, we decline to address comments suggesting alternative site control requirements for interconnection facilities or network upgrades.

(c) Site Control Considerations for Interconnection Customers with Regulatory Limitations

605. We adopt the NOPR proposal, with modification, to revise section 3.4.2 of the *pro forma* LGIP to include a limited option for interconnection customers to submit a deposit in lieu of site control when they submit their interconnection request—only if qualifying regulatory limitations prohibit the interconnection customer from obtaining site control. We adopt the NOPR proposal to provide that interconnection customers with regulatory limitations may submit an initial deposit in lieu of site control of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million. As discussed below, this deposit shall be refundable but may not be applied toward interconnection studies or withdrawal penalties, if applicable. However, we decline to adopt the proposed requirement in the NOPR that an interconnection customer facing regulatory limitations must demonstrate 100% site control prior to the execution of a facilities study agreement. Instead, we modify the proposed requirement for an interconnection customer facing

[1205] Under the *pro forma* LGIP, interconnection facilities shall mean the transmission provider's interconnection facilities and the interconnection customer's interconnection facilities. Collectively, interconnection facilities include all facilities and equipment between the generating facility and the point of interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the generating facility to the transmission provider's transmission system. Interconnection facilities are sole use facilities and shall not include distribution upgrades, stand alone network upgrades or network upgrades.

regulatory limitations to provide that a deposit in lieu of site control will be accepted and held by the transmission provider until the interconnection customer can demonstrate 90% site control prior to execution of the facilities study agreement or 100% site control at execution of the facilities study agreement or thereafter. Additionally, we modify the NOPR proposal to specify in Appendix B of the *pro forma* LGIA that interconnection customers facing qualifying regulatory limitations must demonstrate 100% site control within 180 calendar days of the effective date of the LGIA or the LGIA may be terminated per article 17 (Default) of the *pro forma* LGIA and the interconnection customer may be subject to withdrawal penalties per new *pro forma* LGIP section 3.7.1.1 (Calculation of the Withdrawal Penalty).

606. We adopt the NOPR proposal to revise section 3.4.2 of the *pro forma* LGIP to provide how interconnection customers may demonstrate regulatory limitations. Specifically interconnection customers must provide to the transmission provider: (1) a signed affidavit from an officer of the company indicating that site control is unobtainable due to regulatory limitations as such term is defined by the transmission provider; and (2) documentation sufficiently describing and explaining the source and effects of such regulatory limitations, including a description of any conditions that must be met to satisfy the regulatory limitations and the anticipated time by which the interconnection customer expects to satisfy the regulatory restrictions.

607. With respect to what qualifies as a regulatory limitation, we require transmission providers to define regulatory limitations relevant to their service territory, to publicly post the definition, and to provide a narrative description of how they define regulatory

limitations as part of their compliance filings. While we decline to require a uniform definition of regulatory limitations for all transmission providers, we clarify that a regulatory limitation is generally a federal, state, Tribal, or local law that makes it practically infeasible to obtain site control within the time frame detailed in the *pro forma* LGIP. We allow transmission providers flexibility on how to publicly post the definition, such as by including it in business practice manuals or posting on a publicly accessible website. We consider the definition of regulatory limitations to be an implementation detail appropriately housed outside of transmission providers' tariffs, consistent with the rule of reason. We expect that the appropriate scope of regulatory limitations may vary by region and is likely to need to be updated over time as relevant federal, state, Tribal or local laws change. For these reasons, we do not require transmission providers to include their definitions of regulatory limitations in their tariffs.

608. We believe that these requirements will ensure a transparent, consistent, and orderly process to facilitate demonstration of regulatory limitations by interconnection customers and will establish minimum requirements to provide transmission providers sufficient information to evaluate such demonstrations. We agree with commenters that transmission providers are best positioned to develop appropriate definitions of regulatory limitations to address the specific circumstances and unique regulatory limitations that interconnection customers in their regions may face. We believe that this approach preserves flexibility for transmission providers to account for regional diversity.

609. As noted above, we decline to adopt the proposed requirement in the NOPR that an interconnection customer facing regulatory limitations must demonstrate 100% site

control prior to commencement of the facilities study. We agree with commenters that the requirement to demonstrate site control at the facilities study stage could act as a barrier for generating facilities faced with regulatory limitations in demonstrating site control because the permitting process may still be underway at the facilities study stage.[1206] To account for these barriers, we clarify that, in such circumstances, interconnection customers are permitted to proceed through the interconnection process and execute, or request the unexecuted filing of, an LGIA before obtaining site control, by providing documentation that demonstrates they are taking identifiable steps to secure the necessary regulatory approvals from the applicable federal, state, and/or Tribal entities, as described above. Such interconnection customers must provide this documentation at the time of execution of the facilities study agreement and when executing, or requesting the unexecuted filing of, the LGIA, or alternatively, demonstrate site control in accordance with the requirements of the *pro forma* LGIP.

610. We acknowledge that certain interconnection customers developing generating facilities on sites owned or controlled by a government entity, such as those who site generating facilities on BLM lands, may not be able to demonstrate site control under the *pro forma* LGIP definition even by the later stages of the interconnection process because final permitting approval from BLM may not occur until after the facilities study stage.[1207] We believe the site control requirements included in the *pro forma* LGIP strike

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[1206] *See, e.g.,* NV Energy Initial Comments at 17.

[1207] *See, e.g.*, *id.*

an appropriate balance between disincentivizing speculative interconnection requests and accommodating interconnection customers facing extensive permitting requirements by allowing such customers to submit a deposit in lieu of site control where they demonstrate a qualifying regulatory limitation.

611. In response to commenters' concerns that, without clarification, the regulatory limitations exception to the site control requirement may be interpreted broadly to allow interconnection customers to claim regulatory limitations when obtaining site control is simply impractical or expensive, we reiterate that transmission providers may exercise discretion when defining regulatory limitations—generally a federal, state, Tribal, or local law that makes it practically infeasible to obtain site control within the time frame detailed in the *pro forma* LGIP—as appropriate for interconnection customers in their regions. We believe that allowing flexibility in defining regulatory limitations will enable transmission providers to account for any local, county, Tribal and state regulations in their respective region that may delay an interconnection customer's efforts to obtain site control.

612. With respect to the amount of the deposit in lieu of site control for interconnection customers with regulatory limitations, we find that the amounts that we adopt in this final rule will help prevent speculative interconnection requests without placing an undue burden on interconnection customers. We are not persuaded by commenters that argue that the deposit amounts in lieu of site control for interconnection customers with regulatory limitations need to be even higher to deter interconnection requests that are not likely to achieve site control, particularly when considered in conjunction with the

commercial readiness deposits and withdrawal penalties adopted in this final rule, discussed below. We also find that deposits in lieu of site control for interconnection customers with regulatory limitations should be refundable, but may not be applied toward interconnection studies or withdrawal penalties. We find that making these deposits in lieu of site control for interconnection customers with regulatory limitations non-refundable, as some commenters argue, may unduly burden certain interconnection customers facing regulatory limitations where certain regulatory constraints may be beyond their control.

c. Commercial Readiness

i. NOPR Proposal

613. In the NOPR, the Commission proposed to revise the *pro forma* LGIP to include a commercial readiness framework, which included commercial readiness demonstration options and commercial readiness deposits.[1208] The Commission explained that such a framework would encourage interconnection customers that are not ready to proceed to withdraw from the interconnection queue earlier in the study process while also providing them the flexibility to enter and remain in the interconnection queue without an off-take agreement; reduce the number of times an interconnection customer executes and suspends an LGIA for a speculative interconnection request, only to later withdraw the request, leading to the shifting of network upgrade costs to lower-queued interconnection customers; and reduce the strain on transmission providers and enable viable

[1208] NOPR, 179 FERC ¶ 61,194 at P 128.

interconnection requests to progress more quickly through a less congested interconnection queue, thereby remedying the unjust and unreasonable Commission-jurisdictional rates discussed in Section II of this final rule.

614. Therefore, the Commission proposed to establish the defined terms "commercial readiness demonstration[1209] and "commercial readiness deposit"[1210] in the *pro forma* LGIP.[1211] The Commission also proposed to add to sections 3.4.2, 7.5, and 8.1 of the *pro forma* LGIP the following options as acceptable forms of commercial readiness demonstration to enter into the cluster study and cluster restudy:

- An executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years;
- Reasonable evidence that the generating facility has been selected in a resource plan or resource solicitation process by or for a load-serving entity (LSE),

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[1209] The Commission proposed to revise section 1 of the *pro forma* LGIP to provide that commercial readiness demonstration shall have the meaning set forth in sections 3.4.2, 7.5, and 8.1 of the *pro forma* LGIP. *Id.* P 129 n.204.

[1210] The Commission proposed to revise section 1 of the *pro forma* LGIP to provide that commercial readiness deposit shall mean a deposit paid in lieu of submitting a commercial readiness demonstration, as set forth in sections 3.4.2, 7.5, and 8.1 of the *pro forma* LGIP. *Id.* P 129 n.205.

[1211] *Id.* P 129.

is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer; or

- A provisional LGIA which has been filed at the Commission (executed or unexecuted), which is not suspended and includes a commitment to construct the generating facility.

615. The Commission also proposed to add to section 8.1 of the *pro forma* LGIP the following options to serve as forms of commercial readiness demonstration to enter the facilities study, to be provided with the executed facilities study agreement:

- An executed contract (as opposed to a term sheet), binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years;

- Reasonable evidence that the generating facility has been selected in a resource plan or resource solicitation process by or for an LSE, is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer; or

- A provisional LGIA accepted for filing by the Commission, which is not suspended, with reasonable evidence that the generating facility and interconnection facilities have commenced design and engineering.[1212]

[1212] *Id.* P 130.

616. The Commission also proposed to require the interconnection customer to inform the transmission provider of any material change to its commercial readiness demonstration. The Commission proposed to require the transmission provider to give the interconnection customer 10 business days to demonstrate satisfaction with the applicable requirement after notification of a change to the interconnection request's commercial readiness demonstration.[1213] The Commission explained that the interconnection customer would have the option to submit a commercial readiness deposit within the 10-day cure period if the change to the commercial readiness demonstration meant that the interconnection request no longer satisfied the criteria.

617. The Commission preliminarily concluded that this approach was appropriate for all transmission providers and therefore proposed to allow interconnection customers the option to submit a commercial readiness deposit, in lieu of demonstrating commercial readiness through the commercial readiness demonstration options required to enter a cluster study, cluster restudy, and facilities study.[1214] The Commission noted that, outside of RTOs/ISOs, transmission providers may be able to provide certain contractual arrangements to their own generating facilities or other preferred interconnection customers, such as the term sheet option noted above, which could lead to unduly discriminatory behavior. The Commission stated that this deposit in lieu of demonstrating commercial readiness may potentially prevent any undue discrimination in

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[1213] *Id.* P 131.

[1214] *Id.* P 132.

the generator interconnection process, consistent with the adoption of a standard set of procedures in the first instance.[1215]

618. The Commission proposed to revise the *pro forma* LGIP to include a framework to allow interconnection customers to provide a commercial readiness deposit in lieu of meeting commercial readiness requirements in the following amounts:

- Two times the study deposit amount to enter the initial cluster study phase;
- Five times the study deposit amount after the initial cluster study phase and before the system impact restudy phase; and
- Seven times the study deposit amount after receipt of the facilities study agreement.[1216]

619. The Commission clarified that the proposed commercial readiness deposit is separate from the study deposit.[1217] The Commission stated that the commercial readiness deposit would be returned if the interconnection customer later makes a commercial readiness demonstration. If the interconnection customer withdraws from the interconnection queue, the Commission proposed that the commercial readiness deposit would be applied toward any incurred withdrawal penalties.

620. Additionally, the Commission proposed revisions to the list of development milestones in section 11.3 of the *pro forma* LGIP to clarify the following:

[1215] *Id.* (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 1-2).

[1216] *Id.* P 133.

[1217] *Id.* P 134.

- A contract for the supply or transportation of fuel and a contract for the supply of cooling water will not be accepted for wind, storage, or solar photovoltaic resources;
- Comparable evidence of a contract for the sale of energy or capacity will be accepted; and
- Any of the commercial readiness demonstration options accepted to enter the facilities study will be accepted along with the executed LGIA or within 15 days of the Commission issuing an order on the unexecuted LGIA filing, while a commercial readiness deposit will not be accepted.[1218]

621. The Commission preliminarily found that this framework would allow interconnection customers to calculate the exact deposit that would be required prior to entering the interconnection queue, as it is based on multiples of the study deposit, and the study deposit is based on the size of the proposed generating facility, as chosen by the interconnection customer, leading to predictability in the deposit amount.[1219] The Commission explained that this increased transparency in the deposit amount early in the interconnection process would discourage speculative interconnection requests from entering the interconnection queue.

622. The Commission sought comment on whether the Commission should also establish, as other alternative demonstrations of commercial readiness, evidence of a

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[1218] *Id.* P 135.

[1219] *Id.* P 136.

commitment to participate in RTO/ISO markets, a site-specific purchase order for generating equipment specific to the interconnection request, or a statement signed by an officer or authorized agent of the interconnection customer attesting that the generating facility is to be supplied with major electric generating components (such as wind turbines) with a manufacturer's blanket purchase agreement to which the interconnection customer is a party.[1220]

ii. Comments

(a) Comments in Support

623. Several commenters support the commercial readiness framework because they believe that it will reduce the submission of exploratory or speculative interconnection requests.[1221] These commenters argue that requiring financial commitments and commercial readiness requirements early in the interconnection process, as the Commission proposed, is important to more efficiently allocate transmission provider resources to generating facilities that are more likely to achieve commercial operation

[1220] *Id.* P 137.

[1221] APPA-LPPC Reply Comments at 5; Avangrid Initial Comments at 9; Consumer Energy Initial Comments at 5; EEI Initial Comments at 6-7; EEI Reply Comments at 5; NERC Initial Comments at 26; Google Initial Comments at 20; Idaho Power Initial Comments at 7; MISO TOs Initial Comments at 28-29; NARUC Initial Comments at 10; NESCOE Initial Comments at 13; North Carolina Commission and Staff Initial Comments at 26; Ohio Commission Consumer Advocate Initial Comments at 12; Omaha Public Power Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 3, 6; Pennsylvania Commission Initial Comments at 14; U.S. Chamber of Commerce Initial Comments at 9; UMPA Initial Comments at 5; Xcel Reply Comments at 6-10.

and to enhance the certainty of interconnection study results, benefiting all interconnection customers. Pacific Northwest Utilities similarly assert that requiring commercial readiness at an appropriate point in the cluster study process minimizes the cost and inefficiency risk of restudies and increases the probability that planned network upgrades will be funded and constructed.[1222] Navajo Utility also supports the Commission's use of the commercial readiness requirements to discourage speculative interconnection requests from slowing the interconnection process.[1223]

624. Navajo Utility explains that, as an LSE that constructs generating facilities for the benefit of the Navajo Nation and to export clean energy to surrounding LSEs, it specifically supports the second criterion related to generating facilities developed by an LSE.[1224] NRECA contends that the proposed commercial readiness demonstration requirements protect generating facilities that have been committed to serve load from being hindered by interconnection requests for generating facilities that are still looking for off-takers, thereby helping reduce the pressure on transmission provider interconnection queues.[1225]

625. APPA-LPPC note that there may be power purchase agreements, asset sales agreements and competitive procurement programs that currently contemplate full

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[1222] Pacific Northwest Utilities Initial Comments at 6.

[1223] Navajo Utility Initial Comments at 10.

[1224] *Id.* at 10-11.

[1225] NRECA Initial Comments at 29.

knowledge of interconnection costs before deals may be finalized.[1226] However, APPA-LPPC argue that there is nothing inevitable about the structure and sequencing of these arrangements. APPA-LPPC state that, assuming the Commission moves ahead with a commercial readiness requirement, it is not hard to envision revisions to standard form power purchase agreements, asset sales agreements, and bids into power procurement programs that are contingent on specified assumptions regarding interconnection costs. APPA-LPPC contend that with improvements in the availability of interconnection costs, along with much-needed stability in the interconnection queues, it is reasonable to expect that interconnection costs will be substantially more predictable than is now the case.

626. SoCal Edison supports the proposals to require the interconnection customer to notify the transmission provider of any material change to its commercial readiness demonstration and to require the transmission provider to give the interconnection customer 10 business days to cure the commercial readiness deficiency.[1227]

(b) <u>Comments in Opposition</u>

627. Several commenters argue that the NOPR proposal is inconsistent with prevailing commercial practices (especially those in RTOs/ISOs), sets unreasonable standards for off-take agreements, and ignores the commercial reality of the competitive solicitation process, which could create an undue preference for self-build options in areas that rely on competitive solicitations and undue discrimination against merchant developers,

[1226] APPA-LPPC Reply Comments at 5.

[1227] SoCal Edison Initial Comments at 9.

thereby subverting competition in wholesale power markets.[1228] Some commenters contend that the proposed commercial readiness demonstration options are heavily weighted in favor of incumbent utility practices, such as evidence of a power purchase agreement or executed term sheet or evidence that a project has been selected in a resource plan or resource solicitation process by an LSE.[1229]

628. Enel argues that ratepayers and off-takers benefit from generating facilities being selected in competitive processes that consider both a generating facility's inherent characteristics and its interconnection costs and schedule, which cannot be done if off-take arrangements are made prior to applying for interconnection service.[1230] NextEra asserts that being part of the interconnection queue is an essential step in the competitive process,[1231] and Public Interest Organizations note that utilities conducting RFPs for their resource plans often require at least a position in an interconnection queue as a

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[1228] ACORE Reply Comments at 4; AEE Initial Comments at 20; AEE Reply Comments at 12; Alliant Energy Initial Comments at 5-6; Clean Energy Associations Initial Comments at 34-35; Clean Energy Associations Reply Comments at 4-6; CREA and NewSun Initial Comments at 57; CREA and NewSun Reply Comments at 22-45; Cypress Creek Initial Comments at 22-23; Enel Initial Comments at 44; ENGIE Initial Comments at 5; ENGIE Reply Comments at 2-3; EPSA Initial Comments at 9; Fervo Energy Reply Comments at 6-7; New Jersey Commission Reply Comments at 6-8; NextEra Initial Comments at 24; Pine Gate Initial Comments at 27; NextEra Reply Comments at 14-16; Public Interest Organizations Initial Comments at 29-30; R Street Initial Comments at 13; SEIA Initial Comments at 25; Vistra Initial Comments at 6.

[1229] EPSA Initial Comments at 9; R Street Initial Comments at 13.

[1230] Enel Initial Comments at 44.

[1231] NextEra Initial Comments at 24.

precondition of offering.[1232] Cypress Creek argues that commercial readiness demonstrations should not apply until an interconnection customer receives the results from the proposed initial cluster study, which may be required to bid into a resource solicitation.[1233] Cypress Creek contends that it is impractical to include the proposed demonstration requirements at early stages in the interconnection study process and that this construct is not workable in markets where merchant sales are common.

629. Enel, NextEra, and Public Interest Organizations argue that precluding entry into the interconnection queue due to lack of a demonstration of commercial readiness would be an anticompetitive measure favoring entities, such as incumbent transmission providers, that could favor their own proposed generating facilities ahead of others because of their enhanced ability to demonstrate their proposed generating facilities as commercially ready.[1234] For instance, CREA and NewSun assert that, unlike independent power producers, an incumbent, vertically integrated utility can easily meet the second prong of the readiness criteria to enter the interconnection queue and proceed to the facilities study by simply identifying its preferred resource in its own resource plan, selecting it as the winning bid in its own utility-run RFP, or just attesting that the utility is "developing" the generating facility.[1235]

[1232] Public Interest Organizations Initial Comments at 29.

[1233] Cypress Creek Initial Comments at 22-23.

[1234] Enel Initial Comments at 44; NextEra Initial Comments at 24; Public Interest Organizations Initial Comments at 29.

[1235] CREA and NewSun Initial Comments at 66 (citing NOPR, 179 FERC

630. CREA and NewSun claim that the commercial readiness proposal would drive most, if not all, independent power producers from the market, which would raise costs to consumers by eliminating competition and innovation.[1236] SEIA asserts that by proposing a commercial readiness demonstration framework that is nearly impossible for independent power producers to meet, the Commission is incorrectly implying that generating facilities developed by independent power producers are inherently not commercially viable.[1237] SEIA emphasizes that independent power producers play a critical role in bringing robust competition to markets by driving innovation and decreasing the cost of providing power.[1238]

631. Alliant Energy claims that requiring demonstration of commercial readiness prior to an interconnection customer entering the interconnection queue may do more harm than good.[1239] Alliant Energy argues that the commercial viability of a proposed generating facility depends heavily on the costs of network upgrades and interconnection facilities required to accommodate a generating facility's interconnection, which cannot be known prior to a generating facility receiving cost estimates that are dependable and enable interconnection customers to make decisions during the interconnection process.

¶ 61,194 at PP 129, 130).

[1236] *Id.* at 57.

[1237] SEIA Initial Comments at 16, 25.

[1238] *Id.* at 25.

[1239] Alliant Energy Initial Comments at 5-6.

632. Vistra argues that the proposed increase in study deposits, withdrawal penalties, and exclusive site control requirements will significantly reduce the number of speculative interconnection requests entering the interconnection queue, making the commercial readiness proposal redundant.[1240] Vistra notes that the Commission has relied on fact-specific showings to accept requirements to demonstrate commercial readiness thus far, and Vistra argues that the fact that the Commission has accepted a transmission provider's revised LGIP under FPA section 205 does not establish that the *pro forma* LGIP is unjust and unreasonable without the commercial readiness proposal.[1241]

633. Vistra states that, beyond simple timing concerns, procurement decisions and eligibility to enter the interconnection queue are interrelated in a way that creates a chicken-and-egg problem.[1242] Vistra explains that it is difficult for a generating facility to be shortlisted for procurement without line of sight to obtaining a signed interconnection agreement because the signed interconnection agreement brings more certainty to the generating facility's commercial operation date. Vistra expresses concern that the Commission's proposal to require an executed term sheet to enter the interconnection queue and an executed contract to enter the facilities study process will simply shift the burden of this chicken-and-egg problem to the procurement process. Vistra asserts that

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[1240] Vistra Initial Comments at 6.

[1241] *Id.* at 6, 8.

[1242] *Id.* at 9.

the status quo appropriately balances the inherent difficulty of coordinating procurement and interconnection.

634. Invenergy argues that the proposed requirements are inappropriate and should not be applied nationally because they are based on a small subset of transmission providers that have adopted "readiness" requirements with little evidence that they are effective, given the continuing interconnection queue reform efforts in some of those same regions.[1243] Invenergy adds that, if additional assurance of an interconnection customer's intent to pursue its interconnection request is needed, the Commission should consider a requirement to post a certain amount of security that becomes increasingly at risk to move through the interconnection queue, as is done in some RTO/ISO regions.

635. NextEra asserts that generating facilities may be fully viable based on criteria that are different from what the NOPR proposes. For example, NextEra states that it is possible that storage or other types of generating facilities entering the market will not require power purchase agreements or designation as network resources to be commercially viable.[1244]

636. R Street argues that a key to efficient generating facility development is to enable parallel work flows.[1245] R Street claims that, by imposing extensive prerequisites to advance in the interconnection process, commercial readiness requirements would

[1243] Invenergy Initial Comments at 11-12.

[1244] NextEra Initial Comments at 24.

[1245] R Street Initial Comments at 13.

introduce greater process dependencies in generating facility development. R Street adds that granting non-RTO/ISO transmission providers discretion over commercial readiness requirements could lead to discriminatory behavior (e.g., non-RTO/ISO transmission providers withholding off-take contracts to discriminate against other potential suppliers).

637. MISO states that it is concerned about the utility and impacts of the proposed commercial readiness framework.[1246] MISO explains that interconnection customers with commitments from off-takers can be commercially unready and often cause the greatest interconnection queue disruption by lingering the longest in the queue. As an example, MISO posits a proposed generating facility that would be commercially viable provided it does not incur network upgrade costs in excess of $5 million dollars. MISO argues that such a generating facility is likely to remain in the interconnection queue despite not having a viable business case, in the hopes that other interconnection customers will withdraw their requests and costs will decrease. MISO asserts that, to indicate commercial readiness, a term sheet or contract would need to show not only that there was an off-taker but also that the projected income for the proposed generating facility is sufficient to render the generating facility commercially viable, given estimated study and network upgrade costs, which would be exceedingly difficult to require from interconnection customers and nearly impossible for a transmission provider to evaluate and verify.

[1246] MISO Initial Comments at 62-63.

638. Anbaric claims that the proposed core readiness requirements do not align with the development trajectory of planned transmission projects for offshore wind generation.[1247]

639. NextEra asserts that commercial readiness requirements at the interconnection request stage are inappropriate.[1248] NextEra explains that interconnection customers do not have a simple test for distinguishing speculative interconnection requests from other interconnection requests. Rather, NextEra continues, successful generating facility development depends on whether the interconnection customer concludes that the interconnection arrangement is acceptable and whether the generating facility's location and costs are agreeable to its customers.

640. NextEra also argues that meeting any readiness milestones after the submission of an interconnection request (e.g., when entering the facilities study phase) should be premised on the interconnection customer having received timely and accurate study results, including from affected systems.[1249] NextEra asserts that it is not just and reasonable to impose increasingly strict requirements on interconnection customers without devising means of accelerating interconnection queue processing by transmission providers and ensuring transmission providers comply with their tariffs.

641. Longroad recommends that the Commission clearly tie the interconnection customer's commitment to pay for network upgrades to a security deposit applied toward

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[1247] Anbaric Initial Comments at 15-16.

[1248] NextEra Initial Comments at 23-24.

[1249] *Id.* at 25.

the costs thereof during the cluster study phases, and that the security deposits for network upgrades progressively increase at each stage of the cluster study process.[1250] Longroad asserts that in the initial cluster study, the security deposit should be a modest percentage of the allocated network upgrade cost and increase to, for example, 25% of the network upgrade cost allocation to enter the facilities study. Longroad contends that the interconnection customer should have the option to either fully fund the network upgrade as a milestone in the LGIA or to fund in advance the transmission provider's estimated quarterly spending towards engineering, procurement, and construction of the network upgrades.

(c) Comments on Specific Proposals

(1) Proposed Readiness Demonstrations

642. Commenters raise significant issues with the readiness demonstration options proposed in the NOPR. With respect to the first proposed readiness demonstration option,[1251] commenters argue that providing power purchase agreements or term sheets will be unworkable for most interconnection customers, particularly merchant developers, because: (1) developers do not have sufficient information about interconnection costs to move forward with a term sheet or power purchase agreement at

[1250] Longroad Reply Comments at 13.

[1251] Executed term sheet (or comparable evidence) related to a contract for sale of (1) the constructed generating facility to a load-serving entity or to a commercial, industrial, or other large end-use customer, (2) the generating facility's energy or capacity where the term of sale is not less than five (5) years, or (3) the generating facility's ancillary services where the term of sale is not less than five (5) years.

the time they enter into the interconnection study process; and (2) the proposals to make more information available to interconnection customers prior to submitting an interconnection request will not provide sufficiently granular or certain information to overcome this barrier.[1252]

643. Commenters further note that the vast majority of power purchasers seek generating facilities with advanced interconnection queue positions (with preference for a finalized LGIA or SGIA) before signing a power purchase agreement or finalizing a state procurement.[1253] CREA and NewSun, as well as SEIA, argue that a contract for provision of ancillary services, is almost entirely foreclosed to many non-synchronous generating facilities because nearly every transmission provider bars non-synchronous generating facilities from providing ancillary services, either explicitly or through operating requirements.[1254]

[1252] AEE Initial Comments at 21; AES Clean Energy Initial Comments at 16; CAISO Initial Comments at 18; CESA Initial Comments at 10; CESA Reply Comments at 6; Clean Energy Associations Initial Comments at 37; ClearPath Initial Comments at 8; CREA and NewSun Initial Comments at 57-58; New Jersey Commission Reply Comments at 6-7; Enel Initial Comments at 42-43; Invenergy Initial Comments at 13-15; Invenergy Reply Comments at 1-5; Fervo Energy Initial Comments at 5; Longroad Energy Reply Comments at 17; SEIA Initial Comments at 17; SEIA Reply Comments at 7-9; Shell Reply Comments at 20-21; Longroad Energy Initial Comments at 15-16; Omaha Public Power Initial Comments at 8-9; R Street Initial Comments at 13; Shell Initial Comments 13-15; Vistra Initial Comments at 8, 10.

[1253] Invenergy Initial Comments at 13; Northwest and Intermountain Initial Comments at 9; Public Interest Organizations Initial Comments at 28.

[1254] CREA and NewSun Initial Comments at 62; SEIA Initial Comments at 17.

644. Commenters also assert that, if independent power producers are forced to enter into contracts before costs are certain, then they would need to incorporate that uncertainty into the power purchase agreement offer, which would drive up the costs of these contracts, resulting in higher consumer costs.[1255] Commenters contend that, if the independent power producer does not reflect the costs of the network upgrades in its power purchase agreement price, either the independent power producer or the consumer may attempt to break the contract, which would lead to increased contractual litigation.[1256] Vistra adds that the purchaser will then need to start the procurement process over or choose to over-procure as insurance against potential contract termination, to the detriment of reliability and cost.[1257]

645. SoCal Edison argues that, in some regions, an executed contract option for entering the facilities study could unintentionally encourage LSEs to sign contracts with developers for more energy or capacity than they need to secure resources to meet their procurement targets.[1258] SoCal Edison contends that competition in certain areas for particular generation resources may be high, which may force other LSEs to prematurely

[1255] CREA and NewSun Initial Comments at 57; Clean Energy Associations Initial Comments at 37; SEIA Initial Comments at 17; SoCal Edison Initial Comments at 8; Vistra Initial Comments at 9-10.

[1256] AEE Initial Comments at 21; Longroad Energy Initial Comments at 15; SEIA Initial Comments at 17; Vistra Initial Comments at 10.

[1257] Vistra Initial Comments at 10.

[1258] SoCal Edison Initial Comments at 7-8.

enter into contracts with developers to secure generation without the benefit of the facilities study, which is currently relied on by LSEs to assess commercial viability of a generating facility before contracts are signed. AEE asserts that customers may ultimately bear the cost of the selection of generating facilities that may not be the least cost options in the market but are able to execute a term sheet or power purchase agreement regardless of the ultimate level of interconnection costs.[1259]

646. Commenters also assert that it is unreasonable to expect that a buyer and seller will be able to finalize negotiation of a contract between the time of the cluster restudy (or amendment of the restudy if additional interconnection customers withdraw upon receipt of the restudy results) and the time the facilities study agreement must be executed.[1260]

647. CAISO requests that the Commission describe in detail what would constitute a term sheet.[1261] CAISO states that in its experience with similar tariff provisions, interconnection customers frequently try to submit questionable or even misleading documentation to meet the tariff requirements.

648. Invenergy argues that, to the extent an off-take agreement or term sheet remains an option to demonstrate readiness, the Commission should clarify that transmission

[1259] AEE Initial Comments at 21.

[1260] CREA and NewSun Initial Comments at 62; Longroad Energy Initial Comments at 16; SEIA Initial Comments at 17.

[1261] CAISO Initial Comments at 20.

providers are not entitled or even permitted to review the commercial terms of the term sheet or agreement, which may be confidential and is not subject to the transmission provider's discretion.[1262]

649. GSCE does not dispute that readiness requirements are important but argues that basing them on contracting status is misguided for the following reasons: (1) it does not focus on early-stage developmental steps that drive generating facility viability and indicate true commercial readiness; (2) it provides incentives for interconnection customers that have not taken concrete steps toward readiness to bid low in competitive solicitations, creating fictional "contracted" capacity that may never prove viable; (3) the contracting landscape is evolving, and long-term contracting is no longer required for successful project financing or the emerging realities of capital markets, and with the inflationary environment, long-term contracts may currently be harder to finance than short-term contracts; and (4) a focus on contracting to enter the interconnection study process forces commercial negotiations to occur before generating facilities are studied and have sufficient cost certainty or development timeline assurances.[1263]

650. Commenters also point to significant issues with the second proposed readiness demonstration option.[1264] They argue that requiring evidence that a proposed generating

[1262] Invenergy Initial Comments at 18.

[1263] GSCE Initial Comments at 8-9.

[1264] Reasonable evidence that the generating facility has been selected in a resource plan or resource solicitation process by or for an LSE, is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other

facility is "selected in a resource plan or resource solicitation plan by or for [an LSE], is being developed by [an LSE], or is being developed for purposes of a sale to a commercial, industrial, or other a large end-use customer" is discriminatory and preferential without cause or reasonable support.[1265]

651. Several commenters argue that the option for interconnection customers to demonstrate commercial readiness by showing that the generating facility is being developed for purposes of a sale to an end-use customer suffers a timing challenge because it is nearly impossible for the independent power producer to price a sales contract to a retail customer, or the customer having much interest in discussing the transaction, without having reasonable certainty as to the generating facility's likely interconnection costs.[1266]

652. SoCal Edison recommends that the Commission clarify or give additional examples of reasonable evidence that a proposed generating facility has been selected in an LSE's resource solicitation process or allow a transmission provider to determine how

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large end-use customer.

[1265] AEE Initial Comments at 23; Clean Energy Associations Initial Comments at 35; CREA and NewSun Initial Comments at 58-70; EPSA Initial Comments at 9; Interwest Initial Comments at 19-20; SEIA Initial Comments at 18; Shell Initial Comments at 16.

[1266] AEE Initial Comments at 22-23; CREA and NewSun Initial Comments at 59; SEIA Initial Comments at 19-20; Shell Initial Comments at 14; Vistra Initial Comments at 6.

this option can be met.[1267] SoCal Edison states that evidence that a proposed generating facility has been short-listed in an LSE request for offer should be considered reasonable evidence for moving into the facilities study.

653. Several commenters argue that the third readiness demonstration option, a provisional LGIA,[1268] is likely unworkable as well because it would require independent power producers to assume almost all the risk of the network upgrade costs without knowing those costs.[1269] On the other hand, CAISO asserts that interconnection customers could escape financial consequences and bypass the NOPR's requirements through the provisional LGIA option.[1270] CAISO argues that, at a minimum, the Commission should allow transmission providers to provide the provisional LGIA option where they believe it will work, but not require all transmission providers to enable interconnection customers to bypass commercial readiness through provisional LGIAs.

654. SoCal Edison and CAISO recommend that the Commission provide additional guidance on, or more clearly define, the term "provisional LGIA."[1271] CAISO also states

[1267] SoCal Edison Initial Comments at 8.

[1268] A provisional LGIA that has been filed at the Commission executed, or requested to be filed unexecuted, which is not in suspension pursuant to article 5.16 of the LGIA, and includes a commitment to construct the generating facility.

[1269] AEE Initial Comments at 23-24; CREA and NewSun Initial Comments at 59-63; SEIA Initial Comments at 20-23.

[1270] CAISO Initial Comments at 20-21.

[1271] SoCal Edison Initial Comments at 8; CAISO Initial Comments at 20.

that it is unclear how interconnection customers that have yet to be studied could submit provisional LGIAs because LGIAs describe the network upgrades and facilities from interconnection studies.[1272] CAISO states that interconnection customers are likely to request provisional LGIAs because demonstrating commercial readiness in RTOs/ISOs is generally impossible until after studies are complete.

655. Commenters claim that the record does not support adopting the proposed commercial readiness framework within RTOs/ISOs, arguing that it would be unreasonable and unduly discriminatory.[1273] These commenters argue that the record in RTOs/ISOs does not support the NOPR's assertion that generating facilities are generally not constructed without some form of off-take agreement. They assert that the commercial readiness criteria should not be required *at all* in RTO/ISO regions (with locational marginal price-based markets), where generating facilities can move forward in many cases without a specific off-taker. Some commenters also argue that an RTO/ISO should not have to evaluate contracts for the sale of a generating facility's output or determine whether the generating facility has been selected in a resource plan or resource solicitation process in any of the potentially multiple states within its footprint.[1274]

[1272] CAISO Initial Comments at 20.

[1273] ACE-NY Initial Comments at 6-7; AEE Initial Comments at 22; AES Clean Energy Initial Comments at 16-17; CESA Initial Comments at 9-10; Clean Energy Associations Initial Comments at 38; PJM Initial Comments at 33-34; Public Interest Organizations Initial Comments at 28-29; SEIA Initial Comments at 23-24.

[1274] MISO Initial Comments at 63; MISO TOs Initial Comments at 29; PJM Initial

656. Commenters argue that the proposed 10-business day cure period to resolve potential commercial readiness deficiencies is insufficient given the complicated business and technical decisions involved.[1275] Invenergy states the interconnection process often extends for several years and it is entirely possible that commercial arrangements may change during that time.[1276] Invenergy states that these changes may require additional negotiations, but should not call into question the customer's commitment to developing its project and risk being withdrawn from the interconnection queue. Ørsted requests a 30-business day cure period instead.[1277]

(2) <u>Alternative Commercial Readiness Demonstrations</u>

657. Some commenters argue that the Commission should consider expanding this list of proposed criteria to include other demonstrations of commercial readiness, such as completion of environmental, local, state, or federal permitting processes.[1278] CREA and NewSun, as well as Northwest and Intermountain, ask the Commission to provide QFs a more relaxed readiness option than a fully executed power purchase agreement,

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Comments at 33.

[1275] Invenergy Initial Comments at 21; Ørsted Initial Comments at 13.

[1276] Invenergy Initial Comments at 21.

[1277] Ørsted Initial Comments at 13.

[1278] ClearPath Initial Comments at 9; CREA and NewSun Initial Comments at 71; Enel Initial Comments at 47; Longroad Energy Initial Comments at 17; Northwest and Intermountain Initial Comments at 11; Vistra Initial Comments at 11.

especially when a transmission provider requires qualifying facilities to have a completed interconnection study result to obtain a draft power purchase agreement under its state Public Utility Regulatory Policies Act (PURPA) implementation programs (e.g., PacifiCorp).[1279] CREA and NewSun suggest that the Commission could allow QFs to submit an affidavit from the interconnection customer, stating that the avoided cost rates offered are sufficient to finance and bring the QF into commercial operation if interconnection can be obtained.[1280] CREA and NewSun contend that this option is consistent with the Commission's obligation to adopt regulations that encourage development of QFs.

658. Comments are mixed on the potential additional demonstrations of commercial readiness on which the Commission requested comment in the NOPR. Several commenters support the three potential other readiness options suggested in the NOPR, or a combination thereof.[1281]

659. Other commenters oppose the various alternative demonstration options. With regard to the first—evidence of a commitment to participate in RTO/ISO markets—

[1279] CREA and NewSun Initial Comments at 72-73; Northwest and Intermountain Initial Comments at 11.

[1280] CREA and NewSun Initial Comments at 73.

[1281] *Id.* at 70-71; APS Initial Comments at 15; NERC Initial Comments at 26-27; ENGIE Initial Comments at 5-6; Clean Energy Associations Initial Comments at 39; Invenergy Initial Comments at 16-17; NESCOE Initial Comments at 13; NextEra Initial Comments at 25; Pattern Energy Initial Comments at 31-32; R Street Initial Comments at 13; SEIA Initial Comments at 25; Tri-State Initial Comments at 15.

several commenters argue that the proposal would be essentially meaningless because practically all interconnection requests would qualify.[1282]

660. As for the second and third potential alternative demonstration options—a site specific purchase order for generating equipment specific to the interconnection request, or a statement signed by an officer or authorized agent of the interconnection customer attesting that the generating facility is to be supplied with major electric generating components (such as wind turbines) with a manufacturer's blanket purchase agreement to which the interconnection customer is a party—PacifiCorp and Ameren oppose these options.[1283] PacifiCorp argues that, although it originally adopted a similar provision in its initial interconnection queue reform process, in the course of administering its first two cluster studies, it determined that this readiness option set a low hurdle that speculative interconnection requests could easily overcome.[1284] Similarly, SPP does not support site-specific purchase orders or statements attesting to supply of major components as evidence of commercial readiness.[1285] Enel asserts that it is inappropriate to require procurement of major power equipment prior to an interconnection request or, in many cases, even before executing an LGIA.[1286] Enel contends that requiring

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[1282] Indicated PJM TOs Initial Comments at 31-32; PJM Initial Comments at 34.

[1283] Ameren Initial Comments at 17; PacifiCorp Initial Comments at 31.

[1284] PacifiCorp Initial Comments at 31.

[1285] SPP Initial Comments at 10.

[1286] Enel Initial Comments at 46.

procurement of specific generating equipment prior to applying for interconnection is detrimental to reliability because newer technologies procured after the execution of an LGIA often have advanced features that did not exist a few years earlier. Enel explains that it procures major wind, solar, and battery generation equipment between 12 and 24 months prior to energizing a new generating facility to the transmission system, typically after execution of an LGIA and a full investment review (including knowledge of interconnection costs and schedules) are complete. Enel adds that a generating facility without interconnection results carries too much risk for interconnection customers and investors to risk significant financial deposits to reserve site specific generation equipment. Similarly, Xcel states that interconnection customers want the flexibility to wait until the last minute to order equipment and start construction, which results in different equipment being ordered than initially expected.[1287]

661. Some commenters argue that the proposed commercial readiness requirements unduly discriminate against pumped storage projects, which often do not have the commercial pathways and timelines associated with other types of generating facilities.[1288] Those commenters explain that the development of a pumped storage project is an iterative process of assessment and de-risking that takes several years to complete, at a cost of tens of millions of dollars. They suggest that achieving one of the

[1287] Xcel Initial Comments at 33.

[1288] Hydropower Commenters Initial Comments at 9, 25-26; rPlus Initial Comments at 4.

following three criteria would be sufficient evidence of commercial readiness for a pumped storage project: (1) a filing of notice of intent to apply for an original license and pre-application document with the Commission; (2) an executed memorandum of understanding, letter of intent, or an equivalent term sheet with a utility; or (3) selection of the project in an integrated resource plan (IRP) process. They add that, in lieu of having achieved one of these, a commercial readiness deposit of $2,000 per MW is appropriate. These commenters ask the Commission to add the receipt of a Commission license to the list of milestone developments in section 11.3 of the *pro forma* LGIP.

662. Commenters recommend several alternative bases to determine commercial readiness, including: (1) a 50% generator tie line site control requirement;[1289] (2) a project development plan to determine readiness;[1290] (3) documentation of developer due diligence, including available transmission capacity and modeling;[1291] (4) participating in and meeting the eligibility requirements for a state-mandated procurement program;[1292] and (5) an executed firm point-to-point transmission service agreement from the proposed point of interconnection to a point of consumption for the generating facility's output.[1293]

[1289] Enel Initial Comments at 45.

[1290] Xcel Initial Comments at 33.

[1291] SEIA Initial Comments at 25.

[1292] SoCal Edison Initial Comments at 8.

[1293] Avangrid Initial Comments at 15.

663. To address the Commission's concerns while maintaining the commercial viability of planned transmission projects for offshore wind, Anbaric asks the Commission to consider requiring such projects to make the following demonstrations to satisfy the commercial readiness requirements: (1) site control of property near the point of interconnection suitable for a converter station of a specified size (expressed in MWs) needed to enable high voltage direct current (HVDC) lines carrying offshore wind energy to be put onto the regional transmission system; (2) site control of a property at a coastline location suitable for the transition from seabed to terrestrial routes sufficient to move the specified amount of MWs identified in interconnection requests; and (3) a state procurement policy or goal to procure a defined amount of offshore wind generation associated with a planned transmission project within a defined time frame.[1294]

664. Eversource supports the Commission's proposed commercial readiness framework but asks the Commission to strengthen it by requiring the interconnection customer to demonstrate project financing (along with the current proposed requirements).[1295] Eversource also asks the Commission to require interconnection customers to provide a preliminary project schedule that identifies all key milestones and timelines.

665. Fervo Energy argues that, for cluster study and restudy processes, the proposed framework should allow the interconnection customer to demonstrate readiness by using a combination of options, such as executed term sheets for a portion of the facility plus

[1294] Anbaric Initial Comments at 17-18.

[1295] Eversource Initial Comments at 18.

deposits on a $/MW basis calculated from the quotient of the study deposit amount and the proposed generating facility size.[1296]

666. ENGIE and SEIA ask the Commission to make the commercial readiness demonstration a requirement for entering into an LGIA.[1297] ENGIE and SEIA assert that a later-stage commercial readiness demonstration will allow independent power producers to make rational business decisions based on reasonably certain network upgrade costs.

(3) <u>Deposit in Lieu of Readiness</u>

667. Some commenters contend that the proposal to allow interconnection customers to provide a deposit in lieu of demonstrating commercial readiness does not cure the potential for undue discrimination that results from retaining commercial readiness options that are easily attained by incumbent, vertically integrated utilities but infeasible for independent power producers.[1298] These commenters claim that, because it is nearly impossible for an independent power producer to make any of the commercial readiness demonstrations currently proposed, the deposit in lieu of meeting the commercial readiness requirements would not be an "option" for independent power producers but rather would be the *only* path forward in the interconnection process.

[1296] Fervo Energy Initial Comments at 4.

[1297] ENGIE Initial Comments at 6; SEIA Initial Comments at 25.

[1298] AEE Initial Comments at 24; Clean Energy Associations Initial Comments at 38; NextEra Initial Comments at 24; SEIA Initial Comments at 22-25; Vistra Initial Comments at 6-7.

668. Some commenters support the deposit in lieu of readiness option, as proposed. For instance, SoCal Edison asserts that an increased financial requirement via a deposit in lieu of demonstrating commercial readiness should help to identify those interconnection requests that are economically viable and to which the transmission provider should focus its resources.[1299] Northwest and Intermountain state that providing interconnection customers with an option to demonstrate commercial readiness through a deposit is essential to ensuring a competitive market for generation by providing a way for independent power producers to enter the interconnection queue.[1300] MISO supports the concept of commercial readiness deposits, with the first one due at the time of submission of an interconnection request, which would then be forfeited if the interconnection request does not result in an LGIA, and a second, higher deposit due at the time of execution of an LGIA, to be refunded upon a generating facility achieving commercial operation.[1301] MISO also supports the Commission's proposal to make these deposits separate from, and in addition to, study deposits, as well as MISO's existing milestone requirements in its interconnection study process. MISO believes that these proposals could be a useful deterrent to speculative or unviable interconnection requests entering into or lingering in MISO's interconnection queue.

[1299] SoCal Edison Initial Comments at 9.

[1300] Northwest and Intermountain Initial Comments at 12.

[1301] MISO Initial Comments at 60.

669. MISO TOs argue that, in keeping with the overall theme of flexibility and respect for regional differences, the Commission should afford transmission providers flexibility to adopt readiness requirements and deposit amounts that are appropriate for their regions.[1302] MISO suggests deposits could consist of two components: (1) a minimum amount per interconnection request, regardless of proposed service levels, and (2) a per MW amount.[1303] MISO asks that the commercial readiness deposit increase the pool of money available to offset cost shifts, and any additional monies be utilized to defray the study costs of interconnection customers that actually reach commercial operation.

670. Some commenters argue that allowing deposits and security to be posted in lieu of demonstrating commercial readiness may not be sufficient to accomplish the NOPR's goals,[1304] and may, in fact, hinder the NOPR's goals.[1305] APPA-LPPC assert that the financial commitments proposed in the NOPR, while not insignificant, do not reflect the potentially substantial cost of continuing to tolerate the ongoing uncertainty.[1306] APS claims that, in its experience, speculative interconnection requests are well-funded but

[1302] MISO TOs Initial Comments at 29.

[1303] MISO Initial Comments at 61.

[1304] APS Initial Comments at 15; EEI Initial Comments at 7-8; Idaho Power Initial Comments at 7; Omaha Public Power Initial Comments at 8; Southern Initial Comments at 8.

[1305] APPA-LPPC Initial Comments at 19; APS Initial Comments at 15; Omaha Public Power Initial Comments at 8; Southern Initial Comments at 9-10.

[1306] APPA-LPPC Initial Comments at 19.

may not be commercially viable.[1307] Tri-State asserts that the fact that all 53 applicants in its 2022 interconnection queue elected to provide additional financial security at phase 1 in its study process, instead of one of three readiness milestones, demonstrates that deposits are not effective at deterring unready interconnection requests from entering the interconnection queue.[1308]

671. Other commenters recommend changes to the Commission's proposal. For instance, North Dakota Commission recommends either removing the deposits in lieu of demonstrating readiness or increasing readiness deposit amounts to an amount that provides a quantifiable, evidence-based reduction in speculative interconnection requests.[1309]

672. PacifiCorp states that its interconnection process also allows an interconnection customer to make a payment of $3,000/MW in lieu of meeting commercial readiness demonstration requirements.[1310] PacifiCorp expresses concern that the NOPR proposal would reduce the payment obligation (in comparison to what is required today under PacifiCorp's LGIP), thus lowering the bar for more speculative interconnection requests to enter the interconnection queue and increasing risks for further study delays.

[1307] APS Initial Comments at 15.

[1308] Tri-State Initial Comments at 15-16.

[1309] North Dakota Commission Initial Comments at 5.

[1310] PacifiCorp Initial Comments at 30.

673. CAISO contends that the Commission's proposed deposit requirements are low, such that any modern interconnection customer could meet them.[1311] CAISO questions whether the deposit requirements (or any deposit requirements) would deter uncompetitive interconnection requests or reduce interconnection queue sizes. CAISO argues that using arbitrary figures to set deposit requirements is unlikely to yield meaningful results. CAISO urges the Commission to gather more data or hold a technical conference to develop meaningful deposit amounts, based on data provided by transmission providers.

674. EEI and NRECA suggest further reducing potential risks of speculative interconnection requests by making deposits non-refundable.[1312] NRECA argues that the deposit in lieu of readiness should only be refunded when the interconnection customer has provided an appropriate commercial readiness demonstration or achieves commercial operation, adding that allowing any other refund of this deposit dilutes the effectiveness of this readiness requirement.[1313] EEI and NYTOs assert that a deposit in lieu of readiness should only be allowed in limited circumstances.[1314]

675. Commenters urge the Commission to decline to adopt a commercial readiness standard that is tied to the status of an interconnection customer's off-take arrangements

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[1311] CAISO Initial Comments at 19-20.

[1312] EEI Initial Comments at 8; NRECA Initial Comments at 9.

[1313] NRECA Initial Comments at 29.

[1314] EEI Initial Comments at 7; NYTOs Initial Comments at 20.

and instead to adopt an increasingly "at-risk" readiness deposit framework, similar to what has been accepted in various RTOs/ISOs.[1315] They contend that more directly associating readiness deposits to the estimated costs and likely impact to other interconnection customers if an interconnection customer withdraws would provide greater accountability for interconnection customers and transmission providers.[1316]

676. PJM and Omaha Public Power assert that the Commission should consider basing the readiness deposit amount on an average cost of network upgrades in the region determined during previous studies, as this method would be based on a less arbitrary valuation than as proposed.[1317] SEIA urges the Commission to set the value of the deposit amount as a percentage of the estimated network upgrade costs, which should be capped at $2 million.[1318] rPlus recommends a commercial readiness deposit of $2,000/MW, noting that this figure is common in industry practice.[1319]

[1315] AEE Initial Comments at 20, 24-25; AES Clean Energy Initial Comments at 16-19; Clean Energy Associations Initial Comments at 39; EPSA Initial Comments at 10; Indicated PJM TOs Initial Comments at 30-31; Invenergy Initial Comments at 16; MISO Initial Comments at 64-65; R Street Initial Comments at 13; Shell Initial Comments at 15-16.

[1316] AEE Initial Comments at 20, 24-25; AES Clean Energy Initial Comments at 16- 19; Clean Energy Associations Initial Comments at 39; EPSA Initial Comments at 10; Indicated PJM TOs Initial Comments at 30-31; Invenergy Initial Comments at 16; MISO Initial Comments at 64-65; R Street Initial Comments at 13; Shell Initial Comments at 15-16.

[1317] Omaha Public Power Initial Comments at 8; PJM Initial Comments at 35.

[1318] SEIA Initial Comments at 25.

[1319] rPlus Initial Comments at 4.

677. Some commenters contend that the level of the proposed readiness deposits is too high and should be significantly revised.[1320] Pattern Energy requests that the Commission clarify if these deposits are additive or whether they would require an interconnection customer to have available seven times the study deposit amount by the time the interconnection request reaches the facilities study phase. Pattern Energy states that if the payments are additive, then the Commission would be requiring an interconnection customer to have 14 times its initial study deposit on hand by the time the interconnection customer reaches the LGIA milestone, which Pattern Energy contends would be unreasonable.[1321]

678. Invenergy argues that depositing as much as $3.5 million before learning how much must be spent on network upgrades is not reasonable.[1322] ACE-NY argues that the deposit values for the second cluster and beyond should be limited to just two times the study deposit amount.[1323] CREA and NewSun contend that the hefty deposits will bar smaller companies with less access to capital from competing and entering the interconnection study process.[1324] CREA and NewSun argue that the NOPR's deposit

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[1320] CREA and NewSun Initial Comments at 63; ACE-NY Initial Comments at 7; Invenergy Initial Comments at 15-16.

[1321] Pattern Energy Initial Comments at 31.

[1322] Invenergy Initial Comments at 15-16.

[1323] ACE-NY Initial Comments at 7.

[1324] CREA and NewSun Initial Comments at 65.

levels are purely arbitrary and appear aimed at driving interconnection customers out of the interconnection process rather than measurably improving the process.

679. National Grid requests clarification that transmission providers may deduct from a to-be-returned deposit any expenses incurred by the transmission provider in administering the respective escrow account.[1325]

680. Pattern Energy contends that the Commission must clarify that deposits will be applied toward future security obligations if a generating facility reduces its size as it progresses through the interconnection process.[1326] Pattern Energy states that if the size of an interconnection request is reduced, in accordance with allowable reduction amounts, then: (1) future deposits should be based on the *new* generating facility size; and (2) previous deposits should be credited toward future deposits based on the portion of those previous deposits that are associated with the reduced MW quantity.

(d) <u>Requests for Flexibility</u>

681. Several commenters generally support the proposed commercial readiness requirements but ask the Commission to provide flexibility to allow transmission providers to determine the detailed readiness and deposit criteria for their footprint.[1327]

[1325] National Grid Initial Comments at 24-25.

[1326] Pattern Energy Initial Comments at 31.

[1327] Avangrid Initial Comments at 15; Dominion Initial Comments at 25; Dominion Reply Comments at 10, 13-14; El Paso Electric Initial Comments at 4; Invenergy Initial Comments at 12; ISO-NE Initial Comments at 31; National Grid Initial Comments at 25; NEPOOL Initial Comments at 14; NESCOE Reply Comments at 8; NY Commission and NYSERDA Initial Comments at 8; NYISO Initial Comments at 23;

These commenters argue that such measures need to be carefully balanced to avoid overly burdening interconnection customers with legitimate interconnection requests that are delayed for reasons out of their control. For example, NY Commission and NYSERDA explain that, in New York, renewable energy certificates procured by NYSERDA could demonstrate commercial readiness, and a similar state agency certificate could be used in a different state.[1328]

682. Pacific Northwest Utilities claim that it would be difficult for transmission providers to implement the commercial readiness proposal in regions such as the Northwest without reforming RFP processes and coordinating amongst multiple transmission owners and LSEs.[1329] Pacific Northwest Utilities explain that many generating facilities in the Pacific Northwest use interconnection and transmission services crossing multiple balancing authority areas, which require coordination of timelines, milestones, and off-ramps in both the RFPs and interconnection queues.

(e) <u>Miscellaneous</u>

683. Enel supports the proposed modification to *pro forma* LGIP section 11.3 to require submission of the development milestones concurrently with returning the executed LGIA so that the interconnection customer cannot avoid the demonstration required by

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NYTOs Initial Comments at 20; Pacific Northwest Utilities Initial Comments at 2-4.

[1328] NY Commission and NYSERDA Initial Comments at 9.

[1329] Pacific Northwest Utilities Initial Comments at 4-5.

pro forma LGIP section 11.3 by suspending its LGIA.[1330] However, Enel notes that it is important for the Commission to retain (and reinstitute where removed by specific transmission providers) the ability for interconnection customers to suspend work under their LGIAs for up to three years.

684. Arizona Commission generally supports the prioritization of commercially ready projects and agrees with the proposed readiness criteria, but also encourages the Commission to consider the possibility of allowing market forces to provide discipline to the interconnection process, such as by allowing transmission owners to prioritize generation projects through the use of competitive solicitations.[1331]

685. The Colorado Commission generally supports prioritizing commercially ready interconnection requests and agrees with the proposed readiness criteria.[1332] However, the Colorado Commission emphasizes that the NOPR does not include a mechanism to prioritize among the many viable, and competing, interconnection requests when interconnection service capacity is scarce.[1333] The Colorado Commission argues that, under existing RTO/ISO interconnection processes as well as the proposed revised *pro forma* LGIP, there is limited ability in the interconnection process to consider the generating facility's broader attributes from a system perspective, including cost, timing,

[1330] Enel Initial Comments at 45.

[1331] Arizona Commission Initial Comments at 2.

[1332] Colorado Commission Initial Comments at 1.

[1333] *Id.* at 2.

location, and resource type.[1334] The Colorado Commission asserts that new proposed generating facilities would likely be stuck in cluster studies with no clear or timely prioritization that ensures that the lowest cost or highest value generating facilities come online quickly and at a reasonable cost. The Colorado Commission contends that prioritizing native load and end-use customers and third-party owned generating facilities through competitive bid processes is the most logical criteria to maintain a reliable system at reasonable cost.[1335] To accomplish this, and help the system rationally move forward in a timely manner, the Colorado Commission suggests adding the following additional language to the commercial readiness section: "RTOs and Transmission Providers shall have the ability to create a separate cluster study process or other mechanisms to prioritize executed contracts that serve and benefit native load in accordance with local load-serving resources needs and priorities as determined through equitable competitive bid processes."[1336]

686. AEE, on the other hand, responds to the Colorado Commission by arguing that allowing transmission providers to prioritize generating facilities that are selected through IRP processes or utility procurements and that benefit native load could allow vertically

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[1334] *Id.* at 7.

[1335] *Id.* at 28.

[1336] *Id.* The Colorado Commission also notes that some or all of this proposed language may be more appropriate for section 4 (Queue Position) of the *pro forma* LGIP.

integrated utilities to push preferred generating facilities through the interconnection process and therefore comes with a risk of discrimination.[1337]

687. CESA argues that proposals to prioritize and favor certain generating facilities and interconnection customers must be rejected as violating the Commission's long-standing policies on open access and non-discriminatory interconnection procedures.[1338] CESA contends that the Colorado Commission's proposal is therefore unduly discriminatory and also goes well beyond what the Commission contemplated in the NOPR.

688. Clean Energy Associations state that they support the Commission's instead accepting regionally specific proposals that would align the interconnection process with competitive procurements associated with resource planning, rather than placing them at odds.[1339] Clean Energy Associations state that projects selected though competitive procurement processes are ready projects, and these processes attempt to consider the transmission (interconnection service and transmission service) costs and the production-related costs. Clean Energy Associations state that one way to accomplish this might be to grant resource solicitation clusters a queue position distinct from other clustered projects, but that concept could be extended to ensure more certainty to the bidder and the resource planning entity of the interconnection and delivery requirements and associated rights.

[1337] AEE Reply Comments at 16.

[1338] CESA Reply Comments at 11.

[1339] Clean Energy Associations Initial Comments at 38.

689. Bonneville sees value in applying commercial readiness requirements to the *pro forma* SGIP and SGIA and contends that failing to do so could create a perverse incentive for interconnection customers to break up large projects into smaller projects to avoid stringent commercial readiness requirements under the *pro forma* LGIP.[1340]

iii. **Commission Determination**

690. We adopt a modified NOPR proposal to revise sections 3.4.2, 7.5, 8.1, and 11.3 of the *pro forma* LGIP, insofar as they require interconnection customers to submit commercial readiness deposits, and we do not adopt the NOPR proposal insofar as it included non-financial commercial readiness demonstrations in the *pro forma* LGIP. To effectuate the requirements that we adopt in this final rule, we modify the proposed revisions to sections 3.4.2, 7.5, and 8.1 to remove the proposed readiness demonstrations and to require that the interconnection customer submit the commercial readiness deposit at the beginning of each study in the cluster study process (i.e., the initial cluster study, the cluster restudy, and the facilities study). For the commercial readiness deposit submitted to enter the cluster restudy and the commercial readiness deposit to enter the facilities study, we also modify the NOPR proposal to move from commercial readiness deposits based on study deposit amounts to commercial readiness deposits based on percentages of the interconnection customer's identified network upgrade costs. We also modify proposed section 11.3 of the *pro forma* LGIP to remove the language providing that one of the proposed readiness demonstrations can be provided when the

[1340] Bonneville Initial Comments at 24-25.

interconnection customer returns the executed LGIA or requests that the LGIA be filed unexecuted. We also adopt the definition of commercial readiness deposit but do not adopt the definition of commercial readiness demonstration. We discuss each in turn.

691. We believe that, along with the other reforms adopted in this final rule, the commercial readiness deposits we require will address the need for reform underlying this Section by helping reduce the submission of speculative, commercially non-viable interconnection requests into interconnection queues.[1341] Further, because the interconnection customer's total commercial readiness deposit held by the transmission provider increases as the interconnection process proceeds, we find that this approach will encourage interconnection customers not ready to proceed through the interconnection process—or whose projects become commercially non-viable during the interconnection process—to withdraw earlier in the process, thereby lessening the incidence of late-stage withdrawals that result in delays and restudies. Similarly, by basing the cluster restudy and the facilities study commercial readiness deposits on the interconnection customer's identified network upgrade cost assignment, an interconnection customer will be subject to the cost consequences of its estimated network upgrades *earlier*. As a result, this approach will encourage interconnection customers to withdraw *earlier* in the interconnection process if they face large network upgrade initial cost assignments or encounter other concerns that cause their

[1341] SoCal Edison Initial Comments at 9, Northwest and Intermountain Initial Comments at 12, MISO Initial Comments at 60, PJM Initial Comments at 35.

interconnection request to be uneconomic. By reducing the number of speculative interconnection requests submitted into the interconnection queue and the number of late-stage withdrawals of interconnection requests, we believe that the commercial readiness deposit requirements that we adopt herein will also enable commercially viable interconnection requests to progress more quickly through the interconnection process. Transmission providers will be able to focus their resources on those interconnection requests most likely to achieve commercial operation, to the benefit of all interconnection customers.[1342]

692. The commercial readiness deposit amounts proposed in the NOPR are tied to generating facility size, as they are based on the initial study deposit, which is likewise tied to generating facility size. We adopt the NOPR proposal for the initial commercial readiness deposit, where the interconnection customer pays a deposit of two times the study deposit to enter the cluster study. Basing the initial commercial readiness deposit on the size of the generating facility aligns the size of the deposit roughly with any impact from a withdrawal of the interconnection request, as generally, all else equal,

[1342] Alliant Energy Initial Comments at 6; Avangrid Initial Comments at 9; Consumer Energy Initial Comments at 5; EEI Initial Comments at 6-7; NERC Initial Comments at 26; Google Initial Comments at 20; Idaho Power Initial Comments at 7; MISO TOs Initial Comments at 28-29; NARUC Initial Comments at 10; NESCOE Initial Comments at 13; North Carolina Commission and Staff Initial Comments at 26; Ohio Commission Consumer Advocate Initial Comments at 12; Omaha Public Power Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 3, 6; Pennsylvania Commission Initial Comments at 14; U.S. Chamber of Commerce Initial Comments at 9; UMPA Initial Comments at 5.

increasing the size of the generating facility increases the likelihood of larger, more costly network upgrades and a greater change in interconnection study inputs.

693. However, we are persuaded by several commenters that commercial readiness deposits should be based on assigned network upgrade costs.[1343] Therefore, we modify the remaining commercial readiness deposits (i.e., the second and third commercial readiness deposits) such that, rather than relying on multiples of the initial study deposit, once estimates of network upgrade costs are available, the commercial readiness deposits equate to increasing percentages of the interconnection customer's identified network upgrade cost assignment. Specifically, we adopt a deposit structure where the commercial readiness deposit to enter the cluster restudy is the amount required to bring the total amount of the interconnection customer's commercial readiness deposit to 5% of the interconnection customer's network upgrade cost assignment identified in the cluster study, and the commercial readiness deposit to enter the facilities study is the amount required to bring the total amount of the interconnection customer's commercial readiness deposit to 10% of the interconnection customer's network upgrade cost assignment identified in the cluster study or restudy, as applicable.[1344] We find that tying

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[1343] For assertions that more directly associating commercial readiness deposits to the estimated costs and likely impact to other interconnection customers in the case of withdrawal would provide greater accountability for interconnection customers and transmission providers, *see* AEE Initial Comments at 24-25; AES Clean Energy Initial Comments at 16- 19; CAISO Initial Comments at 23-24; Clean Energy Associations Initial Comments at 39; EPSA Initial Comments at 10; Indicated PJM TOs Initial Comments at 30-31; Invenergy Initial Comments at 16; MISO Initial Comments at 64-65; R Street Initial Comments at 13; Shell Initial Comments at 15-16.

[1344] *See* SEIA Initial Comments at 25 (urging the Commission to set the value of

the commercial readiness deposits to the network upgrade cost estimate requires the interconnection customer to deposit an amount that corresponds to its network upgrade cost estimates earlier and, thereby, can incentivize interconnection customers with large network upgrade cost estimates to withdraw at earlier points in the interconnection process to the extent the network upgrade cost assignment causes the interconnection request to no longer be viable. This approach achieves the Commission's goals of ensuring that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner.

694. We decline to adopt the non-financial commercial readiness demonstrations proposed in the NOPR. We find that the non-financial commercial readiness demonstrations are not necessary to address the subject of these reforms—providing additional deterrence of speculative, commercially non-viable interconnection requests—given the significant, increasing commercial readiness deposits we adopt instead.[1345]

695. We are also persuaded by commenters who express concerns that the non-financial commercial readiness demonstrations in the NOPR proposal may not necessarily serve as appropriate indicators of a proposed generating facility's commercial viability on a national basis. In some instances, the proposed non-financial commercial

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the commercial readiness deposit as a percentage of the estimated network upgrade costs).

[1345] *See N.Y. v. FERC*, 535 U.S. 1, 27 (2002) (declining to require reforms where "FERC determined that the remedy it ordered constituted a sufficient response to the problems FERC had identified").

readiness demonstrations may be unavailable to interconnection customers with commercially viable projects. For example, this may be true as a result of a misalignment of the timing between resource procurement decisions and interconnection study processes or inconsistency with a relevant local commercial practice, rather than because the proposed generating facilities lack commercial viability.

696. As commenters note, resource procurement efforts across the country all have different timelines, and the timeline to demonstrate commercial readiness proposed in the NOPR was not tailored to meet the timelines of multiple state procurement efforts.[1346] As commenters explain, an interconnection queue position is often a precondition of offering into a resource solicitation.[1347] We agree that, absent a regionally tailored tariff process pursuant to which commercial readiness criteria could be aligned with applicable resource solicitation processes, the commercial readiness criteria proposed in the NOPR may not be workable in markets where merchant sales are common, and this generally applicable final rule is not an appropriate forum to dictate regionally tailored solutions.

697. We are further concerned that there may be trade-offs entailed in requiring the proposed non-financial commercial readiness demonstrations, which are more appropriately assessed on a regional, rather than national basis. We agree with Enel that ratepayers may benefit from generating facilities being selected in competitive processes

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[1346] AEE Initial Comments at 21; SoCal Edison Initial Comments at 7-8; Vistra Initial Comments 6-10.

[1347] *See* Cypress Creek Initial Comments at 22-23; NextEra Initial Comments at 24; Public Interest Organizations Initial Comments at 29.

that consider the facilities' interconnection costs and schedule, which cannot be done if off-take arrangements are made prior to applying for interconnection service.

698. In addition, we are concerned that the proposed non-financial commercial readiness demonstrations could incentivize power purchasers in some regions to execute purchase contracts with interconnection customers whose generating facilities will later be determined to be commercially non-viable. As commenters note, this could lead to purchasers having to start the procurement process over or choose to over-procure as insurance against potential contract termination, to the detriment of reliability and cost.

699. Therefore, we are persuaded to adopt a framework that requires a commercial readiness deposit for all interconnection customers, similar to what the Commission has accepted in various RTO/ISO regions.[1348] We find that requiring deposits in amounts substantial enough to demonstrate commitment to reaching commercial operation at progressive milestones throughout the interconnection process will be a sufficient deterrent to speculative behavior—especially when considered as part of the comprehensive package of reform, including increased site control requirements, increased study deposits, and withdrawal penalties, established by this final rule.

700. In the NOPR, the Commission acknowledged the potential that certain non-financial commercial readiness demonstrations *could* provide an unduly discriminatory or preferential advantage to projects being developed by transmission providers or their

[1348] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 158 FERC ¶ 61,003 (2017); *Sw. Power Pool, Inc.*, 178 FERC ¶ 61,015 (2022).

affiliates.[1349] As summarized above, several commenters have raised—and elaborated on—those concerns. Because we find that the commercial readiness deposits that we adopt in this final rule are sufficient to address the relevant need for reform, and therefore do not adopt the proposed non-financial commercial readiness demonstrations, we need not further address those concerns in this final rule.

701. We recognize that the Commission has previously accepted proposals that include commercial readiness demonstration requirements similar to those proposed in the NOPR. Although we find that commercial readiness deposits are sufficient to address the need for reform in this proceeding, this finding does not preclude transmission providers from adopting non-financial commercial readiness demonstrations, provided they meet the relevant standards when requesting a variation, as discussed above.

702. Some commenters suggest that the Commission could add government and environmental permits as commercial readiness demonstrations as an indicator of commercial readiness that is viable both for independent power producers and for transmission providers and their affiliates.[1350] Although the record provides some support for this, we are concerned that permits and studies may expire due to the length of the interconnection process, and those re-permitting and restudy efforts are still at risk

[1349] NOPR, 179 FERC ¶ 61,194 at P 132.

[1350] ClearPath Initial Comments at 9; CREA and NewSun Initial Comments at 71; Enel Initial Comments at 47; Longroad Energy Initial Comments at 17; Northwest and Intermountain Initial Comments at 11; Vistra Initial Comments at 11

of rejection or failure, which could lead to late-stage withdrawals.[1351] We are also concerned about the possible administrative burden placed on transmission providers, as they must determine which types of permits should be accepted as commercial readiness demonstrations and evaluate the validity of different permits submitted by interconnection customers.

703. Pattern Energy requests that the Commission clarify whether the commercial readiness deposits are additive, meaning that, as each phase of the interconnection process is reached, the full amount of each new readiness deposit must be added on top of the full amounts of earlier readiness deposits (as opposed to merely increasing the total amount of the aggregate readiness deposit to match the level specified for that phase). In response, we clarify that, as modified, the commercial readiness deposits in sections 7.5 and 8.1 of the *pro forma* LGIP make clear that for the second and third commercial readiness deposits, the interconnection customer is only required to submit an additional deposit that brings the total commercial readiness deposit to the amount specified in sections 7.5 and 8.1 of the *pro forma* LGIP (5% of the interconnection customer's identified network upgrade cost estimate and 10% of the interconnection customer's identified network upgrade cost estimate, respectively).

704. In response to comments on the magnitude of commercial readiness deposits (e.g., too high or too low), we reiterate that the commercial readiness deposits are part of a package of reforms meant to deter speculative behavior that also includes site control

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[1351] Enel Initial Comments at 47.

requirements and withdrawal penalties. Thus, the commercial readiness deposits are not intended to be of such magnitude to alone prevent speculative behavior as they are intended to work together with other reforms adopted in this final rule, such as site control and withdrawal penalties. We believe that the deposits should not be so high that viable projects from smaller developers are unable to enter the queue. At the same time, they will only achieve the aims if they are sufficiently high to serve as some deterrent, in concert with the other relevant reforms adopted in this final rule. In response to National Grid's request that the final rule provide for the deduction from a to-be-returned deposit of any expenses incurred by the transmission provider or RTO/ISO in administering the respective escrow account, we note that Order No. 2003 required the collection of various deposits without addressing this type of administrative expense.[1352] We find, in this instance, that there is no need to deviate from Order No. 2003, and we decline to adopt tariff revisions to address the management of an escrow account.

705. In response to Pattern Energy's request for clarification of the commercial readiness deposit amounts in the event that an interconnection customer reduces the size of a proposed generating facility, we clarify that because the modified commercial readiness deposit structure is based on network upgrade cost estimates, a size reduction to a proposed generating facility may or may not impact the remaining commercial readiness deposits, depending on whether the size reduction reduces the interconnection customer's assigned network upgrade costs. This is consistent with the requirements for

[1352] Order No. 2003, 104 FERC ¶ 61,103 at PP 91-92, 100, 101, 218-219.

entering the cluster restudy and facilities study adopted in *pro forma* LGIP sections 7.5 and 8.1, respectively, which require commercial readiness deposits based on percentages of the interconnection customer's identified network upgrade costs.

706. Pattern Energy's request to require that previous deposits be credited towards future deposits based on the portion of those previous deposits that are associated with the reduced MW quantity therefore represents the modified commercial readiness deposit framework we adopt. Under this modified framework, an interconnection customer's previous commercial readiness deposits are effectively credited when it pays later commercial readiness deposits (i.e., the second and third commercial readiness deposits); it pays the required amount of a commercial readiness deposit less the amounts paid for through earlier commercial readiness deposits.

707. We also decline to adopt Bonneville's suggestion to add the commercial readiness provisions to the SGIP because the record does not demonstrate a need for such reform at this time. Because we are not adopting the proposed non-financial commercial readiness demonstrations, we do not address comments proposing revisions or clarifications to those demonstrations. Additionally, several commenters provide additional suggestions for the NOPR proposal, including: (1) addressing the Commission's rules for suspending an LGIA;[1353] (2) addressing queue priority;[1354] and (3) better supporting competitive

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[1353] Clean Energy Associations Initial Comments at 38; PPL Initial Comments at 10.

[1354] Arizona Commission Initial Comments at 2; Colorado Commission Initial Comments at 1-2.

procurement processes.[1355] We find these comments to be outside the scope of the NOPR.

d. LGIA Deposit

i. NOPR Proposal

708. In the NOPR, the Commission proposed to require interconnection customers to submit a deposit equal to nine times the amount of its study deposit when executing the LGIA or requesting the filing of an unexecuted LGIA. The Commission explained that this deposit would be fully refunded once the generating facility achieves commercial operation, but if the interconnection customer withdraws after executing the LGIA or after requesting the filing of an unexecuted LGIA, this deposit would be refunded subject to the withdrawal penalty.[1356] The Commission also sought comment on whether to adopt additional provisions or a different framework that would require larger proposed generating facilities to provide a higher deposit amount—such as a per MW framework.[1357]

ii. Comments

709. MISO supports the proposal to require interconnection customers to submit a deposit equal to nine times the amount of its study deposit at LGIA execution because

[1355] Clean Energy Associations Initial Comments at 38; Colorado Commission Initial Comments at 1-2, 7, 28.

[1356] NOPR, 179 FERC ¶ 61,194 at P 108.

[1357] *Id.* P 110.

MISO believes it is necessary to continue the commercial readiness deposit and withdrawal penalty framework until the interconnection request achieves commercial operation.[1358] Shell supports the security deposit obligations used in MISO's and SPP's generator interconnection processes, which include a deposit at LGIA execution.[1359]

710. Invenergy argues that requiring more security at LGIA execution, in addition to the other proposed burdens on interconnection customers in the NOPR, goes beyond the goal of disincentivizing speculative interconnection requests to creating potentially prohibitive burdens on all interconnection customers, including those with commercially viable proposed generating facilities.[1360] Invenergy contends that, while a deposit based on study costs may make sense in earlier stages of the study process when assigned network upgrade costs are not yet known, it is not appropriate after an LGIA is executed and assigned network upgrade costs are known and memorialized. ACE-NY and AES oppose any additional deposits due from an interconnection customer at the signing of the LGIA that are not tied to network upgrade costs.[1361] AES asserts that in many RTOs/ISOs, interconnection customers have to post security for a portion, if not all, of the assigned network upgrade costs associated with an interconnection request, and such

[1358] MISO Initial Comments at 51.

[1359] Shell Initial Comments at 19.

[1360] Invenergy Initial Comments at 6.

[1361] ACE-NY Initial Comments at 5; AES Initial Comments at 14.

posted security is a sufficient incentive to keep an interconnection customer engaged so that they will complete a generating facility after the LGIA is executed.[1362]

711. Several commenters argue that the Commission's LGIA deposit proposal is excessive and potentially exposes ratepayers to unjust and unreasonable costs.[1363] Ørsted would support a lower amount, such as two times the study deposit, because it believes that the current proposal would not necessarily accurately estimate the costs of required network upgrades.[1364] PJM contends that the Commission should allow transmission providers to adopt security amounts and structures that are rationally related to relevant costs.[1365] Cypress Creek asks the Commission to provide a non-arbitrary basis for its proposed security deposit of nine times the study deposit.[1366] Shell argues that the LGIA deposit appears to be a security deposit and adds that MISO and SPP use a separate security deposit obligation that the Commission should consider.[1367]

712. Several commenters argue that study deposits should be refunded in certain circumstances.[1368] Invenergy argues that any deposit due at LGIA execution should be

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[1362] AES Initial Comments at 14.

[1363] *Id.*; Clean Energy Associations Initial Comments at 30; ENGIE Initial Comments at 4; Ørsted Initial Comments at 9; PJM Initial Comments at 24; Shell Reply Comments at 22.

[1364] Ørsted Initial Comments at 9.

[1365] PJM Initial Comments at 24.

[1366] Cypress Creek Initial Comments at 53.

[1367] Shell Initial Comments at 19.

[1368] AES Initial Comments at 14; Invenergy Initial Comments at 7; Ørsted Initial

subject to a $2 million cap and that deposit should be released dollar for dollar as the interconnection customer posts security or makes required payments under the LGIA.[1369] Invenergy asks that the Commission also clarify that, in the event a proposed generating facility does not achieve commercial operation, any deposit forfeited under this proposal offsets, and is not in addition to, any withdrawal penalties that may be imposed. Invenergy adds that it is unreasonable to require that additional deposits be provided when an interconnection customer asks that the LGIA be filed unexecuted, and if the Commission does nonetheless require interconnection customers to post the deposit as a condition of having the LGIA filed unexecuted, the deposit should be refundable if the interconnection customer elects to withdraw within 30 days of the date of the Commission's order in the applicable docket. Ørsted and Shell assert that, for interconnection customers withdrawing after executing the LGIA, all deposits should be refunded in the event that the interconnection customer withdraws as a result of circumstances outside of its control and the withdrawal does not harm any other entity.[1370] AES argues that all study deposits should be refunded at the time of LGIA execution, and opposes any additional deposits not tied to network upgrade costs.[1371]

Comments at 10; Shell Reply Comments at 23.

[1369] Invenergy Initial Comments at 7-8.

[1370] Ørsted Initial Comments at 10; Shell Reply Comments at 23.

[1371] AES Initial Comments at 14.

713. Southern, on the other hand, argues that making deposits refundable may not be stringent enough and therefore may not accomplish the goals set forth in the NOPR.[1372] NRECA also believes that the Commission should consider whether to make these study deposits non-refundable in the case of withdrawal, as a further disincentive for speculative interconnection requests to enter the interconnection queue.[1373]

iii. Commission Determination

714. We adopt, with modification, the NOPR proposal to revise new section 11.3 of the *pro forma* LGIP to require interconnection customers to submit a deposit when executing the LGIA, or requesting the filing of an unexecuted LGIA,and add the new term "LGIA deposit" to section 1 of the *pro forma* LGIP.[1374] Specifically, we modify the NOPR proposal to require interconnection customers to provide a deposit that will increase the total commercial readiness deposit paid to be equal to 20% of the estimated network upgrade costs identified in the LGIA, rather than providing a deposit equal to nine times the amount of the interconnection customer's study deposit, as proposed in the NOPR.[1375]

[1372] Southern Initial Comments at 8-9.

[1373] NRECA Initial Comments at 26.

[1374] LGIA deposit shall "mean the deposit Interconnection Customer submits when returning the executed LGIA, or within 10 Business Days of the LGIA being filed unexecuted at the Commission, in accordance with Section 11.3 of this LGIP."

[1375] At LGIA execution or at the time the request is made to file the unexecuted LGIA, the interconnection customer must deposit the difference between its total commercial readiness deposits submitted at that point and 20% of its estimated network upgrade cost responsibility.

Additionally, revised section 11.3 of the *pro forma* LGIP requires that interconnection customers submit the LGIA deposit when returning the executed LGIA to the transmission provider, or within 10 business days of the interconnection customer requesting that the LGIA be filed unexecuted at the Commission.

715. In the NOPR, the Commission sought comment on whether to adopt additional provisions or a different framework for deposits, including the LGIA deposit.[1376] In response, commenters provided suggestions, including suggestions to base deposits on network upgrade costs.[1377] We agree that tying the LGIA deposit to the network upgrade cost estimate sends a more accurate cost signal to the interconnection customer and better aligns the LGIA deposit to its function of ensuring that network upgrades are paid for and constructed than the NOPR proposal. We also agree with commenters that a deposit based on the study deposit amount may make sense in the early stage of the cluster study process when assigned network upgrade costs are not yet estimated, but later in the process, when network upgrade cost estimates are available, the use of percentages of network upgrade cost estimates more closely indicates interconnection request viability.[1378] This approach also addresses comments that the LGIA deposit, as proposed, may have been arbitrary, excessive, and unreasonable.[1379]

[1376] NOPR, 179 FERC ¶ 61,194 at P 110.

[1377] *See, e.g.*, Longroad Reply Comments at 13; PJM Initial Comments at 24.

[1378] ACE-NY Initial Comments at 5; AES Initial Comments at 14; Invenergy Initial Comments at 6.

[1379] AES Initial Comments at 14; Clean Energy Associations Initial Comments at

716. The NOPR proposed that this deposit would be fully refunded once the generating facility achieves commercial operation, but we are modifying the NOPR proposal to remove that statement from *pro forma* LGIP section 11.3, and as explained further below, this deposit will be used as part of the security the interconnection customer must provide for the construction of network upgrades and transmission provider's interconnection facilities. However, this LGIA deposit could be refunded, subject to the withdrawal penalty, if the interconnection customer withdraws after executing the LGIA or after requesting the filing of an unexecuted LGIA.

717. We also revise the *pro forma* LGIP and *pro forma* LGIA, as suggested by Invenergy,[1380] to treat the LGIA deposit as part of the security the interconnection customer must provide for the construction of network upgrades and transmission provider's interconnection facilities. Article 11.5 (Provision of Security) of the *pro forma* LGIA requires that, 30 calendar days prior to the commencement of construction under its LGIA, the interconnection customer must provide security for a discrete portion of network upgrades and transmission provider's interconnection facilities, as specified in its LGIA. We revise section 11.3 of the *pro forma* LGIP and article 11.5 of the *pro forma* LGIA to require the transmission provider to use the LGIA deposit, in its entirety, before requiring the interconnection customer to submit additional security for

30; ENGIE Initial Comments at 4; Ørsted Initial Comments at 9; PJM Initial Comments at 24; Shell Reply Comments at 22.

[1380] Invenergy Initial Comments at 7.

construction of network upgrades and transmission provider's interconnection facilities. By allowing the transmission provider to draw down this LGIA deposit as construction proceeds, the construction of network upgrades and transmission provider's interconnection facilities can commence quickly thereby streamlining the interconnection process. With this revision, requiring the LGIA deposit to be returned at commercial operation is now unnecessary as there will be no deposit remaining to return; therefore, we decline to adopt the NOPR proposal to do so.[1381]

718. We also revise article 11.5 of the *pro forma* LGIA to require transmission providers to draft Appendix B (Milestones) of the interconnection customer's LGIA to clearly explain and estimate at which point of construction the interconnection customer's LGIA deposit will be depleted, and the interconnection customer must provide additional financial security. In the event the interconnection customer requests suspension of the LGIA under article 5.16 of its LGIA prior to the commencement of construction, the transmission provider is prohibited from using the LGIA deposit to commence construction until the interconnection customer requests to exit suspension and resume construction, unless there is a need for the transmission provider to use a portion of the LGIA deposit to ensure its system is left in a reliable condition during the period of suspension.

719. We do not adopt the suggestion of Ørsted and Shell that, for interconnection customers withdrawing their interconnection requests after executing an LGIA, all

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[1381] NOPR, 179 FERC ¶ 61,194 at P 108.

deposits should be refunded if withdrawal is the result of circumstances outside the interconnection customer's control and the withdrawal does not harm other entities.[1382] We believe that the exceptions to the application of withdrawal penalties discussed in the Section III.A.6.e below appropriately balance the need to deter withdrawals with the reality that withdrawal is not always due to circumstances within interconnection customers' control.

720. In response to Southern's comments that making both study and LGIA deposits refundable may not be stringent enough and therefore may not disincentivize speculative interconnection requests,[1383] we reiterate that, as adopted, the deposits serve different functions. In this instance, the LGIA deposit serves as a credit towards the security the interconnection customer must provide for network upgrades and transmission provider's interconnection facilities. To the extent the LGIA deposit pays for the construction of network upgrades, such a deposit would be refunded through transmission credits in regions that follow the *pro forma* LGIA provisions on crediting.

e. Withdrawal Penalties

i. NOPR Proposal

721. The Commission preliminarily found that withdrawal penalties are needed to account for the harms that can occur when interconnection customers withdraw from the

[1382] *See* Ørsted Initial Comments at 10; Shell Reply Comments at 23.

[1383] Southern Initial Comments at 8-9.

interconnection queue.[1384] The Commission proposed to revise the *pro forma* LGIP to require transmission providers to assess withdrawal penalties to interconnection customers in certain circumstances. Specifically, the Commission proposed to revise the *pro forma* LGIP to require transmission providers to assess withdrawal penalties to interconnection customers that choose to withdraw at any point in the interconnection process or do not otherwise reach commercial operation, unless: (1) the withdrawal does not delay the timing of other proposed generating facilities in the same cluster; (2) the withdrawal does not increase the cost of network upgrades for other proposed generating facilities in the same cluster; (3) the interconnection customer withdraws after receiving the most recent cluster study report and the costs assigned to the interconnection customer have increased 25% compared to the previous cluster study report; or (4) the interconnection customer withdraws after receiving the individual facilities study report and the costs assigned to the interconnection customer have increased by more than 100% compared to costs identified in the cluster study report.[1385] Thus, the Commission proposed that interconnection customers would be exempt from a withdrawal penalty if the withdrawal does not harm other interconnection customers or if the withdrawal follows a significant unanticipated increase in network upgrade cost estimates.

722. The Commission proposed that the withdrawal penalty would increase as the interconnection customer moves through the study process and would also increase if an

[1384] NOPR, 179 FERC ¶ 61,194 at P 140.

[1385] *Id.* P 141.

interconnection customer provides a commercial readiness deposit in lieu of a demonstration of commercial readiness.[1386] For an interconnection customer that provides a commercial readiness deposit in lieu of a demonstration of commercial readiness, the Commission proposed that its withdrawal penalty would be higher and increase as the interconnection customer progresses in the interconnection process.

723. The Commission proposed that the withdrawal penalty for an interconnection customer that provides a commercial readiness deposit in lieu of a demonstration of commercial readiness will be the greater of the study deposit or: (1) two times the study cost if the customer withdraws during the cluster study or after receipt of a cluster study report, capped at $1 million; (2) three times the study cost if the customer withdraws during the cluster restudy or after receipt of any applicable restudy reports, capped at $1.5 million; (3) five times the study cost if the customer withdraws during the facilities study, after receipt of the individual facilities study report, or after receipt of the draft LGIA, capped at $2 million; or (4) nine times the study costs if the customer withdraws before achieving commercial operation and after executing the LGIA or filing an unexecuted LGIA.[1387] The Commission also proposed that the withdrawal penalty revenues be used to fund studies conducted under the cluster study process.

[1386] *Id.* P 142 (citing May Joint Task Force Tr. 75:23-76:1 (Kimberly Duffley) ("I think one of the best practices of the new system that [Duke Energy Progress and Duke Energy Carolinas] have implemented is the increase of withdrawal penalties as the interconnection moves through the process.")).

[1387] *Id.* P 143.

724. The table below summarizes the proposed withdrawal penalty structure for both interconnection requests that have demonstrated commercial readiness and those that have not (by instead submitting a deposit in lieu of demonstrating commercial readiness).[1388]

Phase of Withdrawal	Commercial Readiness Demonstration Provided?	Total Withdrawal Penalty (if greater than study deposit)	Withdrawal Penalty Cap
1	Yes	1 times study costs	No Cap
2	Yes	1 times study costs	No Cap
3	Yes	1 times study costs	No Cap
LGIA	Yes	9 times study costs	No Cap
1	No	2 times study costs	$1 million
2	No	3 times study costs	$1.5 million
3	No	5 times study costs	$2 million
LGIA	No	9 times study costs	No Cap

725. The Commission also proposed to add the defined term "withdrawal penalty" to the *pro forma* LGIP.[1389] The Commission sought comment on: (1) how to define the circumstances in which a withdrawal is deemed to have delayed the timing or increased the cost of network upgrades for other proposed generating facilities in the same cluster,

[1388] *Id.* P 144.

[1389] *Id.* P 145.

including what criteria should be used to determine whether the withdrawal caused the delay or increased cost, and whether to establish a threshold for when a delay or increase in cost will trigger a withdrawal penalty (and if so, what that threshold should be); (2) whether the Commission should consider exceptions to the proposed withdrawal penalties beyond those proposed in the NOPR; (3) whether withdrawal penalties that increase with proposed generating facility size (as measured by MW) would more effectively deter withdrawals that cause the greatest harm; and (4) whether a correlation exists between the size of a withdrawing proposed generating facility and the relative level of harm (in terms of delays and increased cost) to other interconnection customers as a result of the withdrawal.[1390]

ii. Comments

(a) Comments in Support

726. Multiple commenters generally support the Commission's proposed withdrawal penalties and view the proposal as appropriate to reduce the volume of speculative interconnection requests.[1391] Environmental Defense Fund states that, if adopted with

[1390] *Id.* PP 145-148.

[1391] ACE-NY Initial Comments at 7; Ameren Initial Comments at 18; APPA-LPPC Initial Comments at 17-18; APS Initial Comments at 15; CAISO Initial Comments at 21; Consumers Energy Initial Comments at 5; Dominion Initial Comments at 33; MISO Initial Comments at 66; NARUC Initial Comments at 10; National Grid Initial Comments at 26; NextEra Initial Comments at 6; NRECA Initial Comments at 9; NV Energy Initial Comments at 6; NYTOs Initial Comments at 20-21; Omaha Public Power Initial Comments at 9; PPL Initial Comments at 17; SoCal Edison Initial Comments at 10; U.S. Chamber of Commerce Initial Comments at 9; UMPA Initial Comments at 3-5; Vistra Initial Comments at 6-7.

certain of the other NOPR proposals, the Commission's proposed withdrawal penalties are appropriate to address the delays and costs caused by speculative interconnection requests.[1392] Eversource states that properly calibrated withdrawal penalties are essential to dissuade withdrawals and reduce study process delays.[1393]

727. MISO supports the Commission's proposal to impose a withdrawal penalty on withdrawing interconnection customers, a penalty that MISO suggests should be secured by the commercial readiness deposit.[1394] That said, MISO asserts that the study cost for interconnection requests is not that substantial, and MISO does not believe that paying a withdrawal penalty in the amount of only the study costs would be a sufficient deterrent to prevent speculative interconnection requests from entering or remaining in the interconnection queue.

(b) <u>Comments in Opposition</u>

728. Many commenters oppose the withdrawal penalty proposal.[1395] CREA and NewSun encourage instead better cost certainty for interconnection customers earlier in

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[1392] Environmental Defense Fund Initial Comments at 4.

[1393] Eversource Initial Comments at 18.

[1394] MISO Initial Comments at 66-67.

[1395] CREA and NewSun Initial Comments at 74-77; ENGIE Initial Comments at 6; Hydropower Commenters Initial Comments at 26; Interwest Initial Comments at 21; Northwest and Intermountain Initial Comments at 12; New York State Department Initial Comments at 11; Pacific Northwest Organizations Initial Comments at 3-4; rPlus Initial Comments at 5; R Street Initial Comments at 12; SEIA Initial Comments at 25-27; SEIA Reply Comments at 10-11; Shell Initial Comments at 25.

the study process.[1396] CREA and NewSun suggest that the Commission incorrectly assumes that the interconnection customer has adequate visibility into likely interconnection costs, and thus the financial viability of its proposed generating facility before entering the interconnection queue and becoming liable for these penalties. CREA and NewSun state that the NOPR provides no realistic path to know likely interconnection costs prior to entering the interconnection queue.[1397]

729. ENGIE does not support the implementation of withdrawal penalties and notes that withdrawal penalties without meaningful opportunity for interconnection customers to exit the interconnection process are unlikely to incentivize withdrawal.[1398] New York State Department is skeptical that a withdrawal penalty program will be beneficial to ratepayers.[1399]

730. Pacific Northwest Organizations claim that, without access to interconnection cost information and with larger withdrawal penalties, independent power producers may be discouraged from entering the interconnection queue.[1400] Some commenters claim that withdrawal penalties (including in a transitional cluster study process) can result in the

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[1396] CREA and NewSun Initial Comments at 74, 77.

[1397] *Id.* at 76.

[1398] ENGIE Initial Comments at 6.

[1399] New York State Department Initial Comments at 11.

[1400] Pacific Northwest Organizations Initial Comments at 3-4.

potential for discrimination against independent power producers.[1401] These commenters assert that LSEs can recover withdrawal penalties they incur from their retail ratepayers, whereas independent power producers must absorb these costs and risks in their solicitation process bids. Interwest also suggests that the proposed withdrawal penalties are less likely to apply to LSEs than to independent power producers because LSEs will likely be able to use the proposed commercial readiness demonstration path, as opposed to paying the deposits in lieu of demonstrating commercial readiness, and would thus not be subject to the harsher withdrawal penalties.[1402] Interwest urges the Commission to require waiver of, or a substantial reduction in, withdrawal penalties from the transition cluster or resource solicitation cluster if the interconnection customer participated in an RFP or other competitive solicitation process but was not ultimately selected, or if a permit becomes unavailable due to some regulatory or regime change.[1403]

731. R Street claims that the proposal risks imposing severe anti-competitive barriers to entry.[1404] New York State Department makes similar anti-competitive impact arguments.[1405] R Street asserts that imposing financial commitments and readiness

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[1401] Interwest Initial Comments at 21; Northwest and Intermountain Initial Comments at 12.

[1402] Interwest Reply Comments at 13-14.

[1403] Interwest Initial Comments at 21.

[1404] R Street Initial Comments at 12.

[1405] New York State Department Initial Comments at 11.

requirements can create regulatory barriers to entry if they deter interconnection requests for commercially viable generating facilities or increase financing costs.[1406] R Street argues that the proposal is misguided because it would add another administrative process that increases implementation complications and costs.[1407] R Street suggests that the Commission should instead use a simple loss of deposit as its financial lever.

732. rPlus argues that withdrawal penalties, particularly when coupled with the proposed study deposit requirements and study cost allocations, are unduly discriminatory or punitive to pumped storage as compared to other renewable technologies.[1408] rPlus and Hydropower Commenters claim that, under these proposals, a large capacity pumped storage project (ranging from 400 MW to over 1,000 MW in size, according to rPlus) would expect to hit the maximum deposit and/or penalty in every stage of the interconnection process.[1409] rPlus claims that the high cost of entry and the liability associated with withdrawal may give large utilities an unfair advantage in commercial negotiations.[1410]

733. Shell calls for a reconsideration of the withdrawal penalties proposed in the NOPR, claiming that the proposal could disrupt project development when paired with

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[1406] R Street Initial Comments at 12.

[1407] *Id.* at 14.

[1408] rPlus Initial Comments at 5.

[1409] *Id.*; Hydropower Commenters Initial Comments at 26.

[1410] rPlus Initial Comments at 5.

the proposed commercial readiness requirements and financial commitments (for deposits and site control).[1411] Shell suggests that the Commission adopt withdrawal penalties modeled on MISO's framework, which encourages interconnection customers to withdraw from the interconnection queue with refunded deposits rather than penalizing interconnection customers for making justifiable decisions. Shell contends that there should only be a large penalty for late-stage withdrawals.[1412] Shell contends that, otherwise, the Commission is sending the wrong signal and driving out competition without linking the underlying issue of unexpected network upgrade costs that typically come from affected system studies that are provided very late in the study process.

734. Some commenters contend that increasing the amount of money at stake for an interconnection customer without providing off-ramps from the interconnection process at reasonable decision points where previously unavailable information is supplied does not necessarily incentivize interconnection customers to exit the interconnection queue.[1413] CREA and NewSun suggest that the proposed withdrawal penalties may incentivize an interconnection customer to remain in the interconnection queue waiting for other interconnection customers to withdraw, and the penalty those interconnection customers pay will eventually be distributed to the remaining interconnection customers

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[1411] Shell Initial Comments at 9, 24; Shell Reply Comments at 26.

[1412] Shell Initial Comments at 25.

[1413] CREA and NewSun Initial Comments at 76; SEIA Initial Comments at 25-27; SEIA Reply Comments at 10-11.

in the cluster, or interconnection customers may elect to remain in the interconnection queue in the hopes that others in the cluster withdraw to the point where the cost of network upgrades become more palatable.[1414]

(c) Comments on Specific Proposal

(1) Withdrawal Penalty Amounts

735. Several commenters oppose the proposed withdrawal penalty amounts.[1415] AEE argues that the Commission's proposed withdrawal penalty amounts are overly punitive, especially for those interconnection customers that submit a deposit in lieu of demonstrating commercial readiness, which many interconnection customers will be forced to do under the Commission's proposed commercial readiness requirements.[1416] AEE and Clean Energy Associations assert that the Commission's proposed withdrawal penalty amounts also appear arbitrary, with no basis in the costs of conducting studies or other relevant factors.[1417] AEE argues that the Commission should reduce these amounts and tie them more closely to its objectives and to the study costs that transmission providers are expected to incur, which it asserts will avoid turning the penalties into a

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[1414] CREA and NewSun Initial Comments at 76.

[1415] AEE Initial Comments at 19; CREA and NewSun Initial Comments at 75; Interwest Initial Comments at 22.

[1416] AEE Initial Comments at 19.

[1417] *Id.*; Clean Energy Associations Initial Comments at 41.

punitive measure that provides a profit opportunity for transmission providers.[1418] AEE contends that the withdrawal penalty frameworks and time frames should be designed to discipline the decisions of interconnection customers rather than being punitive. Google does not support the proposal to impose higher withdrawal penalties on interconnection customers that submit a deposit in lieu of demonstrating commercial readiness.[1419]

736. Interwest argues that some of the proposed withdrawal penalties—those in the range of five to nine times the study costs—far exceed reasonableness, especially in the face of the potential for a myriad of ways in which an LSE can bias the bid review process and slow the cluster study process under existing rules without stringent oversight.[1420] Interwest argues that the NOPR does not sufficiently acknowledge the need to reform study processes to prevent inaccurate studies, which create widely different results from one study to another.[1421] Interwest suggests that these inaccurate studies, along with delayed affected system study results, lead to withdrawals, strengthening the case that withdrawal penalties should not increase dramatically toward the end of the study process and around execution of an LGIA without appropriate recourse for the interconnection customer. Interwest argues that a 25% increase in study costs from one study to another should be a sufficient basis for withdrawal without

[1418] AEE Initial Comments at 19-20.

[1419] Google Initial Comments at 21.

[1420] Interwest Initial Comments at 22.

[1421] Interwest Reply Comments at 13-14.

incurring withdrawal penalties, as part of a tariff with incentives for transmission providers to provide accurate estimates of network upgrade costs. Interwest argues that, for these reasons, withdrawal penalties are redundant and punitive when combined with increasingly large at-risk deposits as proof of commercial readiness.

737. SDG&E asserts that a withdrawal penalty of nine times the study deposit amount will provide a disincentive for late-stage withdrawals in certain cases, but that a penalty alone should not be relied on in lieu of other financial security mechanisms.[1422] SDG&E maintains that a more reasonable amount for a withdrawal penalty may be the greater of nine times the study deposit and a CAISO-style financial security posting that is based on factors such as network upgrade and interconnection facilities costs.

738. Some commenters argue that the Commission should adopt the RTO/ISO model of financial readiness milestones that are tied to network upgrade costs.[1423] Clean Energy Associations submit that tying deposits and penalties to network upgrade costs allocated to the interconnection customer is superior because network upgrade costs are a better indicator of the harm that may be caused by a withdrawal than generating facility size.[1424]

739. AES contends that tying the withdrawal penalty to the percentage of network upgrade deposit at risk provides a better incentive for interconnection customers with

[1422] SDG&E Initial Comments at 6.

[1423] ACE-NY Initial Comments at 8; AES Initial Comments at 19; AES Reply Comments at 3-6; Enel Initial Comments at 4; Invenergy Initial Comments at 24; Pine Gate Initial Comments at 34.

[1424] Clean Energy Associations Initial Comments at 41.

proposed generating facilities with high network upgrade costs to withdraw earlier in the interconnection process, rather than risk losing their posted security.[1425] Invenergy suggests that any withdrawal penalty imposed after LGIA execution should be tied to assigned network upgrade costs and should be subject to a $2 million cap to avoid unnecessarily punitive penalties, as the LGIA may impose additional financial obligations for construction of the assigned upgrades.[1426] CAISO argues that network upgrade-based financial requirements are far more effective than the withdrawal penalties proposed in the NOPR because network upgrade-based requirements are tied to the project's actual interconnection costs, which correlate with its competitiveness to obtain a power purchase agreement and therefore its likelihood to remain in the queue.[1427]

740. NYISO argues that the withdrawal penalty amounts proposed in the NOPR, which are tied to study costs, are unlikely to provide sufficient capital to cover the costs of constructing the network upgrades of withdrawn generating facilities on which other interconnection customers are relying.[1428] SoCal Edison suggests that, instead of using study costs as the basis for the withdrawal penalty amount, which would not be known until completion of the interconnection studies, the Commission should require that

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[1425] AES Initial Comments at 19.

[1426] Invenergy Initial Comments at 24.

[1427] CAISO Initial Comments at 23.

[1428] NYISO Initial Comments at 25.

withdrawal penalties be calculated based on increasing multiples of the study deposits, which are known and serve as a proxy of the study costs.[1429]

(2) Proposed Withdrawal Penalty Exemptions

741. Some commenters support the NOPR proposal to exempt interconnection customers from withdrawal penalties in certain instances, stating that the proposal achieves a workable balance between the needs of interconnection customers and transmission providers.[1430] For example, MISO agrees that interconnection requests that experience significant cost increases should be able to withdraw without a penalty.[1431] Omaha Public Power states that the four scenarios proposed in the NOPR for interconnection customers to qualify for exemptions to withdrawal penalties seem to properly acknowledge instances where other interconnection customers are not negatively impacted by a withdrawal, or when it is no longer economically viable for the interconnection customer to move forward with the generating facility due to drastically increased network upgrade costs.[1432]

742. On the other hand, SEIA contends that, although the NOPR proposal exempts interconnection customers from withdrawal penalties if there is no impact to other

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[1429] SoCal Edison Initial Comments at 10.

[1430] MISO Initial Comments at 68; Omaha Public Power Initial Comments at 9-10.

[1431] MISO Initial Comments at 68.

[1432] Omaha Public Power Initial Comments at 9-10.

generating facilities in the same cluster, withdrawals almost always impact other generating facilities in the cluster, such that withdrawal penalties are likely unavoidable.[1433] Pine Gate states that the proposed list of withdrawal penalty exemptions is not reflective of an appropriate balance between interconnection customer and transmission provider accountability because it increases the burden on interconnection customers without any increase to accountability for transmission providers.[1434] Pattern Energy disagrees with a standard tied to a potential delay of a lower-queued interconnection customer, given the Commission's proposed transition to a cluster study approach.[1435] Pattern Energy contends that the only impact that should be relevant to granting an exemption is a financial impact.

743. NRECA supports including the 100% cost increase exemption in the final rule, which would apply where there is a large late-stage cost increase, making the interconnection request's success economically challenging.[1436] Pattern Energy, on the other hand, claims that the Commission's proposal incentivizes transmission providers to overestimate costs in cluster studies for fear that there will be later, unexpected cost increases in the facilities study, which Pattern Energy argues presents a barrier to

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[1433] SEIA Initial Comments at 26.

[1434] Pine Gate Initial Comments at 34.

[1435] Pattern Energy Initial Comments at 33.

[1436] NRECA Initial Comments at 30.

entry.[1437] Pine Gate also claims that requiring a 100% increase in costs between the facilities study phase and the previous cluster study phase in order to allow for penalty-free withdrawal exposes interconnection customers to withdrawal penalties in instances where costs increase dramatically due to no fault of the interconnection customer.[1438] Several commenters recommend that the Commission ensure that any penalties for withdrawal account for unanticipated cost increases.[1439]

[1437] Pattern Energy Initial Comments at 34.

[1438] Pine Gate Initial Comments at 35.

[1439] Clean Energy Associations Initial Comments at 40 (arguing that the Commission should allow interconnection customers to withdraw without penalty if costs in a restudy increase by over 25% relative to prior study results); CREA and NewSun Initial Comments at 78 (suggesting that withdrawal penalties should not apply anytime an interconnection customer withdraws after receipt of a system impact study, facilities study, or restudy that contains a 25% cost increase over the prior study or a 50% cumulative increase over the initial study); ENGIE Initial Comments at 7; Invenergy Initial Comments at 25 (arguing that the Commission should allow interconnection customers to withdraw without penalty if affected system study results cause an interconnection customer's costs to increase by more than 25% compared to costs allocated to it by the host transmission provider in a prior study); Longroad Energy Initial Comments at 18 (recommending that the Commission reduce the penalty exemption threshold to a cost-increase of only 20% from the initial cluster study to the restudy and a cost increase of only 10% from the final restudy to the individual cluster facilities study); NextEra Initial Comments at 26 (suggesting that a more reasonable withdrawal penalty exemption threshold for cost increases for late-stage withdrawals would be in the range of 30%); Ørsted Initial Comments at 15 (arguing that the Commission should allow interconnection customers to withdraw without penalty if costs in a restudy increase by over 25% relative to prior study results); Pattern Energy Initial Comments at 33 (suggesting that, if costs increase by 15% from the first to the second study report, but a restudy results in an additional 20% increase compared to the second study report, then the total increase from the first study report to the restudy report would be 35%, and this total additive percentage increase should be deemed sufficient to constitute an excusable withdrawal event); Pine Gate Initial Comments at 35.

744. Xcel recommends that the Commission allow an interconnection request, submitted by a resource planning entity as agent for an interconnection customer, that is withdrawn by the resource planning entity because it was not picked in a resource solicitation process, to be exempt from withdrawal penalties, as the withdrawal was due to no fault of the interconnection customer.[1440] Xcel states that, other than this exemption, the Commission should not expand the exemptions from withdrawal penalties beyond those proposed in the NOPR.

745. NextEra and Northwest and Intermountain argue that interconnection customers should be exempt from withdrawal penalties if the transmission provider's or affected system operator's studies or posted information are untimely.[1441]

746. NextEra contends that the NOPR does not explain why there are different withdrawal penalty levels for interconnection customers demonstrating commercial readiness via the proposed non-financial demonstration options and those submitting a deposit in lieu of demonstrating commercial readiness.[1442]

747. Several commenters argue that the proposed exemptions require clarification.[1443] For one, CAISO claims that the exemption criteria, as written in the NOPR, are not

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[1440] Xcel Initial Comments at 35.

[1441] NextEra Initial Comments at 26; Northwest and Intermountain Initial Comments at 13.

[1442] NextEra Initial Comments at 27.

[1443] CAISO Initial Comments at 21-22; Environmental Defense Fund Initial Comments at 4-5; EEI Initial Comments at 8; EEI Reply Comments at 6-7; Eversource

workable.[1444] CAISO argues that the Commission's description of the exemptions is problematic due to the use of "or," which suggests meeting any criterion would relieve the interconnection customer of withdrawal penalties. CAISO posits that, under the Commission's criteria, a withdrawal could not affect the timing of other generating facilities but still increase their costs; however, the interconnection customer would meet the first exemption and not be subject to withdrawal penalties. CAISO argues that withdrawals would never delay the timing of generating facilities in the same cluster. CAISO states that a cluster's upgrades are a package, and the construction schedule would not change simply because one interconnection customer that is sharing upgrades withdraws. CAISO suggests that the Commission clarify that, to be exempt from withdrawal penalties, each interconnection customer must meet (1) both criterion one and two, and (2) criterion three or four.

748. Invenergy proposes that the list of exemptions to withdrawal penalties be revised to include: (1) the withdrawal does not directly cause material delays in the timing of other interconnection requests within the same cluster, as determined at the time of withdrawal by the transmission provider; or (2) the withdrawal does not directly cause a material increase in the costs assigned to other interconnection requests within the same cluster, as determined at the time of withdrawal by the transmission provider.

Initial Comments at 19; Shell Reply Comments at 27.

[1444] CAISO Initial Comments at 21-22.

749. Omaha Public Power contends that the exemption to withdrawal penalties cannot be applied to the interconnection process as it currently functions for those transmission providers that allow for overlapping studies (e.g., when a cluster study is being studied prior to the conclusion of the preceding cluster study).[1445] Omaha Public Power claims that overlapping studies lead to baseline costs in the subsequent cluster studies that are inherently wrong and do not factor in the previously existing unfinished cluster studies. Omaha Public Power claims that this inaccurate starting point for costs is likely higher than what is accurate, and any subsequent restudy will likely lead to identification of network upgrades that fall below the exemption threshold, subjecting interconnection customers to wrongful withdrawal penalties. Omaha Public Power argues that, until an interconnection process can be conducted without overlapping studies, these exemptions will be woefully misapplied. Southern raises similar concerns.[1446]

750. Yet other commenters believe that the NOPR proposal is too lenient.[1447] NRECA suggests that transmission providers should be afforded flexibility whether to adopt exemptions to withdrawal penalties related to: (1) not delaying the timing of other interconnection requests in the same cluster; (2) not increasing the cost of network upgrades for other interconnection requests in the same cluster; and (3) withdrawing if the most recent cluster study report shows a cost increase of at least 25% compared to the

[1445] Omaha Public Power Initial Comments at 10.

[1446] Southern Initial Comments at 21-22.

[1447] NRECA Initial Comments at 30; SDG&E Initial Comments at 6-7.

previous cluster study report.[1448] NRECA asserts that these exemptions may or may not be needed for a particular transmission provider and potentially may allow withdrawals that trigger time-consuming restudy processes. SDG&E generally opposes exemptions to withdrawal penalties and claims that material modification provisions in the *pro forma* LGIP already address impacts to other interconnection customers.[1449] SDG&E argues that, regardless of the impact to other interconnection customers, there are still costs and resources committed between all entities to study and assess proposed generating facilities. SDG&E believes that withdrawal penalties should apply for all generating facilities, and any exemptions should be sparing.

(3) How to Determine if a Withdrawal Has Delayed or Increased the Cost of Network Upgrades for Other Generating Facilities in the Same Cluster

751. Some commenters argue that it would be difficult to define the circumstances under which a withdrawal is deemed to have delayed the timing or increased the cost of network upgrades for other interconnection requests in the same cluster.[1450] APS and Bonneville argue that attempting to do so would create an undue burden on transmission providers, and that the withdrawal of an interconnection request could have an impact on

[1448] NRECA Initial Comments at 30.

[1449] SDG&E Initial Comments at 6-7.

[1450] APS Initial Comments at 16-17; Bonneville Initial Comments at 12; MISO Initial Comments at 67.

generating facilities in a subsequent cluster.[1451] NextEra suggests that one test to determine whether a withdrawal delays other interconnection requests could be whether the withdrawal delays the planned in-service date of other interconnection requests in the same cluster.[1452] However, NextEra acknowledges that even this assessment could be difficult to calculate, as delays could not manifest themselves for months or years, other factors could cause delays, and interconnection customers could seek to delay their generating facilities for commercial reasons. Pattern Energy asserts that the Commission must clearly define the standard for timing delays and increasing the cost of network upgrades for other interconnection customers.[1453]

752. Bonneville suggests that, similar to the method used to assess a material modification under the *pro forma* LGIP and *pro forma* SGIP, the Commission could provide a non-exhaustive list of examples that would be deemed as delaying the timing or increasing the costs of network upgrades.[1454] Bonneville suggests that transmission providers could be given discretion to determine whether other withdrawal situations that are not listed should fall under this category by considering whether the withdrawal has delayed the timing or increased the cost of network upgrades for other interconnection requests in a cluster.

[1451] APS Initial Comments at 16-17; Bonneville Initial Comments at 12.

[1452] NextEra Initial Comments at 26.

[1453] Pattern Energy Initial Comments at 33.

[1454] Bonneville Initial Comments at 12.

753. Invenergy argues that transmission providers should not be permitted to simply assume that withdrawals cause some harm to other interconnection requests and that there should be a requirement for transmission providers to perform an analysis to determine whether a withdrawal results in material harm to other interconnection requests, which interconnection customers could review.[1455] Invenergy states that the analysis of whether a withdrawal causes a cost increase or delays the timing for other interconnection requests should be performed at each phase of the study process.

754. Invenergy requests that the Commission clarify that a withdrawal will not delay the timing of another interconnection request or increase its network upgrade costs if the withdrawal simply requires the transmission provider to account for the withdrawal. Invenergy requests that the Commission clarify that any delay or cost increase analysis must be based on a reasonable analysis and show a direct relationship between the withdrawal and the asserted impact on another interconnection request.

755. MISO encourages the Commission to impose the withdrawal penalty whenever an interconnection request withdraws from the interconnection queue.[1456] MISO argues that even if after restudy it turns out that the withdrawal of an interconnection request did not actually increase network upgrade costs to other interconnection customers in the cluster, the withdrawal still negatively impacts the interconnection queue by increasing uncertainty for other interconnection customers, prompting further withdrawals and

[1455] Invenergy Initial Comments at 26-27.

[1456] MISO Initial Comments at 67-68.

adding administrative cost and burden that impede efficient interconnection queue processing. Pattern Energy likewise argues that the withdrawal of any interconnection request from the interconnection queue results in some form of delay, such as the time taken by a transmission provider to perform a review of the potential impacts of the withdrawal, which could be interpreted as causing a delay because the withdrawal impact analysis could delay the receipt of final study results and agreements.[1457] PJM makes similar arguments.[1458]

756. Xcel contends that, if a withdrawal results in a restudy of a cluster or subsequent clusters, that restudy will delay the receipt of study results, LGIA execution, and the construction of required network upgrades.[1459] Therefore, Xcel argues that any withdrawal that results in a restudy should not be exempt from a withdrawal penalty unless the commercial operation dates of other impacted interconnection requests in the same or subsequent cluster are not impacted. Xcel asserts that delaying LGIA execution may negatively impact off-take agreements and should also be considered harm to equally or lower-queued interconnection customers. Xcel notes that harm is not limited to the reallocation of interconnection costs to equally or lower-queued interconnection requests. Xcel contends that delays, resulting in clogged interconnection queues, can impact resource decisions and thus harm interconnection requests not yet in the

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[1457] Pattern Energy Initial Comments at 33.

[1458] PJM Initial Comments at 41.

[1459] Xcel Initial Comments at 33-34.

interconnection queue. Xcel argues that, if the withdrawal causes restudy, but the restudy does not impact the timing discussed above, then the restudy results should be used to determine the impact on costs allocated to equally or lower-queued interconnection requests.

757. Xcel notes that it may be difficult to determine if a single withdrawal would have caused harm when multiple interconnection requests are withdrawn in the same time frame.[1460] Xcel generally supports penalizing withdrawals if they have a combined impact, as it would be difficult, if not impossible and time consuming, to determine each individual withdrawal's impact. According to Xcel, if the withdrawal penalty was determined on an individual basis, some interconnection customers may wait for others to withdraw, then argue that their secondary withdrawals did not have an impact because all delays and cost impacts were caused by the first withdrawal.

758. Indicated PJM TOs state that a withdrawal can impose costs on other interconnection customers even if it does not delay the timing of other proposed generating facilities. Indicated PJM TOs argue that if withdrawals impose more network upgrade costs on other interconnection customers, it would be unfair to excuse withdrawing interconnection customers just because the transmission provider can keep to its original timelines.[1461] Indicated PJM TOs further claim that, particularly in a large RTO/ISO, it is not clear how the transmission provider would determine that a particular

[1460] *Id.* at 34.

[1461] Indicated PJM TOs Reply Comments at 35-36.

withdrawal did or did not delay the processing of other interconnection requests. Indicated PJM TOs argue that this criterion for being excused from penalties or forfeitures should be eliminated.

(4) <u>Withdrawal Penalty Collection and Distribution</u>

759. APS seeks clarification on the mechanism the Commission proposes for transmission providers to collect withdrawal penalties from interconnection customers.[1462] APS and MISO express concerns that, under the withdrawal penalty collection proposal, a transmission provider would have to act as a collection agency, which is likely unworkable.[1463] EEI suggests that the Commission institute financial assurance requirements for interconnection customers to reduce the likelihood that penalized entities are unable to pay the penalties they are assessed.[1464] Eversource asserts that the Commission should set clear rules that include policies governing how RTOs/ISOs will collect penalties and address potential scenarios in which interconnection customers refuse to pay or declare bankruptcy.[1465] MISO claims that

[1462] APS Initial Comments at 16.

[1463] *Id.*; MISO Initial Comments at 69.

[1464] EEI Initial Comments at 8.

[1465] Eversource Initial Comments at 19.

interconnection customers can structure the businesses behind the interconnection request in such a way so that the legal entity would be very difficult to collect from.[1466]

760. Some commenters do not support the Commission's proposal to require withdrawal penalty revenues to be used to fund studies conducted under the cluster study process.[1467] CAISO states that transmission providers already have provisions specifying where non-refundable funds go, and using them for interconnection studies would require careful accounting without relieving study burdens.[1468] NextEra and PJM suggest that transmission providers should be allowed to use forfeited funds to help pay for increased network upgrade costs incurred by other interconnection customers due to a withdrawal.[1469] Invenergy asserts that excess funds should be applied to offset network upgrade costs assigned through that cluster study process in proportion to any upgrade costs that were directly shifted from a withdrawn interconnection customer.[1470] RWE Renewables assert that withdrawal penalties should be used to create meaningful decision points for interconnection customers, to discern whether they are willing to commit

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[1466] MISO Initial Comments at 69.

[1467] CAISO Initial Comments at 22; Interwest Reply Comments at 14; NextEra Initial Comments at 27-28; PJM Initial Comments at 39; RWE Renewables Initial Comments at 2.

[1468] CAISO Initial Comments at 22.

[1469] NextEra Initial Comments at 27-28; PJM Initial Comments at 39.

[1470] Invenergy Initial Comments at 27-28.

resources to each particular generating facility.[1471] RWE Renewables and Interwest contend that withdrawal penalties should be allocated between and among different clusters for transmission expansion, so that they benefit load and interconnection customers, rather than restudies, which they believe will not be needed as frequently in the proposed cluster study process.[1472]

761. CAISO opposes the NOPR proposal to cap withdrawal penalties.[1473] CAISO contends that larger projects create the most churn in queue, and projects that cannot demonstrate commercial readiness should be the most likely to withdraw. CAISO argues that withdrawal penalty caps will disproportionately affect smaller and more competitive interconnection requests more than larger and less competitive interconnection requests and suggests that the Commission remove the withdrawal penalty caps so the withdrawal penalties affect interconnection customers equally.

762. Pattern Energy suggests that, in addition to the Commission's proposed use of withdrawal penalties to defray future study costs, the Commission should designate a portion of any withdrawal penalties to be used for recruitment, retention, and performance bonuses for engineers, administrators, and/or consultants, who can then be deployed to help alleviate queue backlogs.[1474]

[1471] RWE Renewables Initial Comments at 2.

[1472] *Id.*; Interwest Reply Comments at 14.

[1473] CAISO Initial Comments at 24.

[1474] Pattern Energy Initial Comments at 34.

763. Other commenters request clarification of the proposal for distribution of withdrawal penalty funds. AES and EDF Renewables argue that it is critical that the Commission clarify that transmission providers do not receive any benefits from withdrawal fee and non-refundable deposit proceeds; otherwise, they argue, transmission providers would be financially incentivized to force interconnection customers to withdraw.[1475] Several commenters request clarification of the Commission's intent for excess money that remains after funding any appropriate restudies for the current cluster, and some of these commenters have suggested uses for this excess.[1476] AES asserts that any withdrawal fees and non-refundable deposits collected should go towards improving the interconnection process.[1477] EDF Renewables suggests that any remainder should be refunded to the interconnection customer.[1478] On the other hand, Southern opposes refunding excess penalty amounts to the interconnection customer and proposes that any remaining amounts be applied to network upgrades needed in the same cluster or treated as a revenue credit against the revenue requirement in the determination of transmission rates.[1479] APS suggests that the remainder act as a credit towards the transmission

[1475] AES Initial Comments at 19-20; EDF Renewables Initial Comments at 7.

[1476] AES Initial Comments at 19-20; APS Initial Comments at 16; EDF Renewables Initial Comments at 7; Invenergy Initial Comments at 27-28; ISO-NE Initial Comments at 33; Southern Initial Comments at 22.

[1477] AES Initial Comments at 19-20.

[1478] EDF Renewables Initial Comments at 7.

[1479] Southern Initial Comments at 22.

provider's transmission rates, as this method would guarantee that all transmission customers benefit from the penalties.[1480]

764. Shell claims that withdrawal penalties will accumulate faster than they may be spent by the relevant transmission provider.[1481] Therefore, Shell asserts that the Commission must address the following: (1) the system of independent checks and balances that transmission providers will employ to ensure that only specific individuals have access to the withdrawal penalty account; (2) the average cost of a cluster study from start to finish so that, if a withdrawal penalty is forfeited, it can be determined how many future cluster studies the transmission provider could expect to perform with forfeited funds; (3) if funds from a withdrawal penalty are used to pay for future study costs, whether future interconnection customers must still post a study deposit; and (4) if a withdrawal penalty account balance accumulates faster than funds can be spent, what independent system of checks and balances transmission providers will use to ensure that their staff and/or consultants do not overcharge for their services related to studies.

(d) Requests for Flexibility, Clarification, or Technical Conference

765. Some commenters would prefer that the Commission allow for transmission providers to craft and use their own withdrawal penalty structure instead of having a standardized approach for all transmission providers.[1482] AEP supports the adoption of

[1480] APS Initial Comments at 16.

[1481] Shell Initial Comments at 18-19.

[1482] AEP Initial Comments at 24; Avangrid Initial Comments at 9; Avangrid Reply

withdrawal penalties with reasonable penalty-free off ramps but asserts that this is an area in which flexibility should be permitted, particularly where alternative approaches already have been through robust stakeholder processes.[1483] NYTOs suggest that there should be flexibility regarding the amount of the withdrawal penalties, which NYTOs argue should be tied to each transmission provider's and associated transmission owners' interconnection processes.[1484] Pacific Northwest Utilities argue that the Commission should allow flexibility as to the timing of the penalties.[1485] Pacific Northwest Utilities also request flexibility to define their own requirements for withdrawal penalties to limit interconnection queue overcrowding.[1486] Interwest contends that the Commission should not attempt to predetermine the amount of withdrawal penalties in a rulemaking proceeding with limited evidence; rather, the Commission should require that transmission providers develop appropriate mechanisms and determine appropriate monetary amounts to substantially reduce the risk that the efforts of interconnection

Comments at 4; CREA and NewSun Initial Comments at 77-78; Dominion Initial Comments at 34; Indicated PJM TOs Initial Comments at 33; NYISO Initial Comments at 24; NYTOs Initial Comments at 21; Omaha Public Power Initial Comments at 11; OMS Initial Comments at 13; Pacific Northwest Utilities Initial Comments at n.6; PJM Initial Comments at 41; SDG&E Initial Comments at 6; SEIA Initial Comments at 27; Southern Initial Comments at 20; Shell Initial Comments at 24-25; SPP Initial Comments at 11.

[1483] AEP Initial Comments at 23-24.

[1484] NYTOs Initial Comments at 21.

[1485] Pacific Northwest Utilities Initial Comments at 2, 4-5, & n.6.

[1486] *Id.* at 2.

customers are not thwarted or delayed by others' overly speculative interconnection requests.[1487]

766. Some commenters seek general clarification on several of the withdrawal penalty proposals. For example, NV Energy requests clarification on whether, if a withdrawal penalty is deemed appropriate at the time an interconnection customer withdraws its interconnection request, that the interconnection customer is charged both the actual costs incurred to perform studies and the applicable withdrawal penalty (i.e., two separate charges).[1488]

767. NV Energy seeks clarification, if an interconnection customer's generating facility does not achieve commercial operation, whether the nine times the actual study cost deposit would be applied toward its withdrawal penalties, and whether the interconnection customer would be charged nine times the actual study costs.

768. Southern suggests that, in the NOPR's proposed definition of "withdrawal penalty" and in the exemptions to that penalty, the phrase "the commercial operation date in the interconnection request" should replace the phrase "commercial operation," such that the definition would read "the penalty assessed by Transmission Provider to an Interconnection Customer that chooses to withdraw from the queue or does not otherwise reach the Commercial Operation Date in the Interconnection Request."[1489] Southern

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[1487] Interwest Reply Comments at 13.

[1488] NV Energy Initial Comments at 6-7.

[1489] Southern Initial Comments at 21-22.

argues that to be consistent and clear with *pro forma* LGIP section 3.7.1.1, the definition of withdrawal penalty must be revised to reflect that the withdrawal penalty is applicable if the interconnection customer is deemed withdrawn.

769. Invenergy requests that the Commission clarify that, to the extent withdrawal penalty amounts are used to fund some portion of an interconnection study, that it does not reduce the transmission provider's potential exposure for penalties in the event that study is not timely completed.[1490]

770. Invenergy requests that the Commission clarify that, to the extent any post-LGIA withdrawal penalty is imposed, it is offset by the deposit posted at LGIA execution and not additional to that deposit, which would be unreasonable and unnecessarily punitive.[1491]

771. MISO encourages the Commission to bolster the definitions of "commercial readiness deposit," "study deposit," and "withdrawal penalty" to clearly enable the transmission provider to apply those deposits toward the withdrawal penalty.[1492]

772. CAISO seeks clarification that the NOPR's proposed withdrawal penalties would not displace transmission providers' other existing procedures and penalties that incentivize interconnection customers to withdraw earlier rather than later and cites its

[1490] Invenergy Initial Comments at 28.

[1491] *Id.* at 24.

[1492] MISO Initial Comments at 68-69.

own requirement that interconnection customers post financial security based on their allocated network upgrade costs.[1493]

773. NV Energy requests that the Commission clarify what happens if only a portion of an interconnection request is brought to commercial operation, as it relates to withdrawal penalties and the construction of network upgrades.[1494]

774. Tri-State requests clarification on the meaning of "previous withdrawal penalty revenue received" in section 3.7.1.1 of the *pro forma* LGIP[1495] and requests clarification on whether section 3.7.1.2 of the *pro forma* LGIP includes the paragraph after (c) regarding commercial operation.

(e) **Alternatives and Miscellaneous**

775. Some commenters provide comments in response to the Commission's query on whether a correlation exists between the size of a withdrawing proposed generating facility and the relative level of harm, in terms of delays and increased cost, to other interconnection customers as a result of the withdrawal.[1496] Some commenters indicate that there can be a correlation between the size of a withdrawing proposed generating facility and the relative level of harm caused by the withdrawal and encourage

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[1493] CAISO Initial Comments at 22-23.

[1494] NV Energy Initial Comments at 7.

[1495] Tri-State Initial Comments at 28.

[1496] NOPR, 179 FERC ¶ 61,194 at P 148.

withdrawal penalties that increase with the proposed generating facility size.[1497] For example, Idaho Power contends that large generating facilities typically trigger more expensive network upgrades which, when withdrawn, are more likely to trigger restudies.[1498] Other commenters do not support withdrawal penalties that increase based on the size of a generating facility.[1499] APS argues that the determinant of "relative level of harm" is entirely subjective to the transmission provider and could lead to litigation.[1500] APS argues that the location of the interconnection request is more closely correlated with the effect on other interconnection customers than is the size of a proposed generating facility. Xcel states that, although larger generating facilities tend to have a larger impact, if the total impact to other projects is calculated as a combined impact, then the size of the project should not impact the withdrawal penalty calculation.[1501]

776. Ørsted expresses concern that relatively small generating facilities (by MW) that fail to demonstrate commercial readiness and are forced to withdraw from the interconnection queue pose significant threats to the efficient management of the cluster

[1497] Avangrid Initial Comments at 20; Clean Energy States Initial Comments at 10; Enel Initial Comments at 35; Idaho Power Initial Comments at 8; PPL Initial Comments at 17.

[1498] Idaho Power Initial Comments at 8.

[1499] APS Initial Comments at 17; Xcel Initial Comments at 35.

[1500] APS Initial Comments at 17.

[1501] Xcel Initial Comments at 35.

study process and recommends that withdrawal penalties be correlated to an interconnection customer's commercial readiness.[1502]

777. AEP supports the idea of off-ramp opportunities at specific times in the cluster study process rather than having to analyze individual withdrawal impacts throughout a cluster study process.[1503] AEP contends that such an approach should limit restudies and minimize delays to remaining interconnection customers. Similarly, PJM asserts that only allowing withdrawals during certain decision points ensures that studies start and finish at the same time and that the cluster status is maintained during the duration of the study.[1504] According to PJM, allowing withdrawals at any point in the study process, as proposed in the NOPR, even with relevant penalties assessed, will cause cascading restudies and negative impacts on other interconnection customers in a cluster.

778. SPP states that, under its current LGIP, interconnection customers provide progressively increasing financial security deposits at each stage of the study process, and the amounts of the financial security deposits required to enter into later stages of the study process are based on the amount of network upgrade costs assigned in the previous stage, which it asserts is better related to the risk and harm of a withdrawal than the NOPR proposal.[1505]

[1502] Ørsted Initial Comments at 13.

[1503] AEP Initial Comments at 24.

[1504] PJM Initial Comments at 41.

[1505] SPP Initial Comments at 11.

779. Rather than being assessed withdrawal penalties, CREA and NewSun assert that interconnection customers should be refunded any unused study deposits.[1506] CREA and NewSun argue that penalties should apply only to deter wrongful conduct that the interconnection customer can avoid committing and should not be used as an arbitrary barrier to market entry.[1507]

iii. Commission Determination

780. We adopt, with modifications, the NOPR proposal to impose withdrawal penalties on interconnection customers for withdrawing their interconnection requests from the interconnection queue, absent qualification for one of the limited exemptions, as discussed below. We add the defined term "withdrawal penalty," as modified below, to the *pro forma* LGIP; revise section 3.7 of the *pro forma* LGIP; and add sections 3.7.1, 3.7.1.1, and 3.7.1.2 to the *pro forma* LGIP, with the modifications to the NOPR proposal discussed below. However, we decline to adopt the withdrawal penalty caps proposed in the NOPR.

781. We find that, along with the other reforms adopted in this final rule, adopting a withdrawal penalty framework is needed to remedy the issues regarding speculative interconnection requests, including study delays from overcrowded interconnection queues and the harms to the function of the interconnection queue that occur when interconnection customers withdraw from the interconnection queue at various stages of

[1506] CREA and NewSun Initial Comments at 77.

[1507] *Id.* at 74-75.

the study process. We believe that withdrawal penalties—as adopted herein—will encourage interconnection customers to ensure that their proposed generating facilities are likely commercially viable when they submit their interconnection requests because withdrawal, in most instances, will incur a penalty. We adopt withdrawal penalties that increase in amount as interconnection customers proceed through the interconnection process in order to ensure that interconnection customers continue to evaluate whether their proposed generating facilities are commercially viable, thereby reducing the number of late-stage withdrawals and accompanying restudies.[1508] We additionally modify the proposal, as discussed below, regarding how the withdrawal penalty funds are distributed. Specifically, after withdrawal penalty funds are used to fund studies conducted under the cluster study process in the same cluster, as proposed in the NOPR, we modify the proposal to require any remaining withdrawal penalty funds be used to offset net increases to network upgrade cost assignments experienced by interconnection customers from the same cluster that remain in the interconnection queue and are directly affected by the withdrawal of an interconnection request because they previously shared an obligation to fund a network upgrade[1509] with the withdrawn interconnection request in

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[1508] *See* RWE Renewables Initial Comments at 2 (asserting that withdrawal penalties should be used to create meaningful decision points for interconnection customers to demonstrate project commitment through the interconnection process).

[1509] Sharing an obligation means (1) interconnecting to the same substation network upgrade, or (2) in the case of a system network upgrade, where interconnection customers are identified through the proportional impact method, as contributing to the need for the same system network upgrade.

the same cluster.[1510] If the interconnection customer withdraws before it executes its LGIA or requests to file its LGIA unexecuted and after the interconnection customers in the same cluster that the withdrawn interconnection customer participated in have executed LGIAs, requested their LGIAs to be filed unexecuted, or withdrawn (or have been deemed withdrawn), any remaining withdrawal penalty funds not applied to study costs or net increases in network upgrade cost assignments must be returned to the withdrawn interconnection customer.[1511]

782. As explained in Section II of this final rule, we find that Commission-jurisdictional rates have been rendered unjust and unreasonable due to speculative interconnection requests that enter and remain in the interconnection queue. By incentivizing interconnection customers to submit interconnection requests only for proposed generating facilities that they believe will be commercially viable and to remain in the interconnection queue only as long as that continues to be true, and by offsetting increases in network upgrade cost responsibility experienced by interconnection customers directly affected by a withdrawal because they share an obligation to fund a

[1510] *See* Invenergy Initial Comments at 27-28; NextEra Initial Comments at 27-28; PJM Initial Comments at 39; Southern Initial Comments at 22 (suggesting that transmission providers should be allowed to use forfeited funds to help pay for increased network upgrade costs incurred by other interconnection customers in the same cluster due to a withdrawal). We disagree with RWE Renewables and Interwest that withdrawal penalties should be allocated between and among different clusters because we find that withdrawal penalties should only be allocated to interconnection customers that are directly affected by a withdrawal because they share an obligation to fund a network upgrade. *See* RWE Renewables Initial Comments at 2; Interwest Reply Comments at 14.

[1511] *See* EDF Renewables Initial Comments at 7.

network upgrade with the withdrawn interconnection request in the same cluster, we believe that the withdrawal penalty requirements will work in tandem with the other reforms adopted in this final rule to remedy those unjust and unreasonable rates.

783. Specifically, we adopt the NOPR proposal, with modification, to revise the *pro forma* LGIP to require the transmission provider to assess withdrawal penalties, unless an exemption applies at any point in the interconnection process. The withdrawal penalties will be applied to an interconnection customer if: (1) the interconnection customer withdraws its interconnection request at any point in the interconnection process; (2) the interconnection customer's interconnection request has been deemed withdrawn by the transmission provider at any point in the interconnection process; or (3) the interconnection customer's generating facility does not reach commercial operation (such as when an interconnection customer's LGIA is terminated prior to reaching commercial operation). We note that a withdrawal could trigger minor adjustments to the study results of the remaining equally- or lower-queued interconnection requests that do not represent a significant harm to those remaining in the queue. Therefore, we are modifying the NOPR proposal to require the transmission provider to assess a withdrawal penalty only if the withdrawal has a material impact on the cost or timing of any interconnection requests with an equal or lower queue position. If the transmission provider determines that the impact of the withdrawal is immaterial, the transmission provider must not assess a withdrawal penalty.

784. We adopt this provision in place of the NOPR proposal to exempt interconnection customers from withdrawal penalties if: (1) the withdrawal does not delay the timing of

other proposed generating facilities in the same cluster; or (2) the withdrawal does not increase the cost of network upgrades for other proposed generating facilities. We adopt the NOPR proposal that the interconnection customer will also be exempt from paying a withdrawal penalty if (1) the interconnection customer withdraws its interconnection request after receiving the most recent cluster study report and the network upgrade costs assigned to the interconnection customer's request have increased 25% compared to the previous cluster study report, or (2) the interconnection customer withdraws its interconnection request after receiving the individual facilities study report and the network upgrade costs assigned to the interconnection customer's request have increased by more than 100% compared to costs identified in the cluster study report. Accordingly, with these exemptions from the withdrawal penalty, the required withdrawal penalty approach adopted herein does not allow for penalties if the impact of the withdrawal is immaterial to other interconnection customers or if the withdrawal follows significant, unanticipated increases in network upgrade cost estimates.

785. For the withdrawal penalty exemptions, we clarify that the relevant cost increases are network upgrade cost estimate increases, and we adopt revisions to the *pro forma* LGIP accordingly. This clarification is consistent with the Commission's description of these exemptions in the NOPR: "Thus, under this proposal, interconnection customers would be exempt from a withdrawal penalty . . . if the withdrawal follows a significant unanticipated increase in *network upgrade* cost estimates."[1512]

[1512] NOPR, 179 FERC ¶ 61,194 at P 141 (emphasis added).

786. We disagree with commenters that the thresholds to trigger the exemptions—a 25% increase in estimated network upgrade costs above the cluster study report estimate or a 100% increase in estimated network upgrade costs in the facilities study report—are too high. As an initial matter, the potential interconnection customer will have access to heatmap information, as required in this final rule, that will allow it to evaluate project feasibility without a financial commitment and thereby avoid potential withdrawal penalty risk. As stated by Omaha Public Power and Southern, upon entering the interconnection queue and receiving the estimates provided in the cluster study report, the interconnection customer is aware that the estimates may change. Additionally, we find that the trigger thresholds are set at an amount that provides sufficient room for estimates to change as the cluster evolves while limiting interconnection customer exposure to withdrawal penalties when such estimates change by a significant amount. Moreover, the increasing threshold triggers reflect the fact that estimates should improve in accuracy as interconnection customers move through the interconnection process and should increasingly disincentivize commercially non-viable generating facilities from staying in the interconnection queue. An interconnection customer will know to factor in both the cost estimates and the potential withdrawal penalty but also the exemption trigger thresholds as it proceeds through the interconnection queue.

787. We do not believe that interconnection customers will be subject to "wrongful withdrawal penalties" as suggested by some commenters. In addition, the withdrawal penalty exemptions are designed to allow penalty-free withdrawal if the withdrawal does not materially harm other interconnection customers or if the withdrawal follows a

significant unanticipated increase in network upgrade cost estimates. The withdrawal penalty exemptions are not designed to mitigate all business risk associated with interconnecting a new generating facility. The withdrawal penalty structure adopted herein, where the withdrawal penalty at the earlier stages of the interconnection process is generally lower than the withdrawal penalty at later stages also lessens the cost exposure for an interconnection customer that withdraws at an earlier stage, when the impact of the withdrawal is less disruptive to the administration of the interconnection queue and other interconnection customers. We find that, by increasing the withdrawal penalty amounts as the interconnection customer proceeds through the interconnection queue, interconnection customers will be incentivized to withdraw non-viable interconnection requests earlier in the process, leading to fewer late-stage withdrawals.

788. We also disagree with commenters that request additional exemptions to the withdrawal penalty structure. We believe that the withdrawal penalty exemptions and withdrawal penalty structure, as modified by this final rule, will deter unwarranted assessments of withdrawal penalties.

789. Regarding commenters' requests for clarification concerning how to determine whether a withdrawal impacts other interconnection requests with the same or lower queue positions for purposes of assessing qualification for an exemption to a withdrawal penalty, we defer to the transmission provider's discretion because the transmission provider is best suited to determine whether a withdrawal has a material impact on the cost or timing of any interconnection customer with the same or lower queue position.

790. We do not adopt the NOPR proposal regarding withdrawal penalty calculations for interconnection customers that provide demonstrations of commercial readiness because we do not adopt the non-financial commercial readiness demonstration options in this final rule, as discussed above in Section III.A.6.c.iii. Instead, we modify the proposed penalty structure to base the withdrawal penalty calculation on an increasing percentage of the cost of the identified network upgrades assigned to the interconnection customer as the interconnection customer moves through the interconnection queue.[1513] We also decline to adopt the withdrawal penalty caps proposed in the NOPR. We believe that this structure will provide better financial incentives for interconnection customers to avoid late-stage withdrawals that cause the greatest disruption to interconnection queue processing via restudies and delays because interconnection customers will be subject to higher withdrawal penalties late in the interconnection process.

791. With regard to the withdrawal penalty calculation structure more specifically, we modify the NOPR proposal and require that, unless an interconnection customer qualifies for one of the stated exemptions discussed above, the transmission provider must assess a withdrawal penalty on an interconnection customer with a proposed generating facility that does not reach commercial operation based either on the actual study costs or on a percentage of the interconnection customer's assigned network upgrade costs, depending

[1513] *See* Invenergy Initial Comments at 27-28; NextEra Initial Comments at 27-28; PJM Initial Comments at 39; Southern Initial Comments at 22 (suggesting that transmission providers should be allowed to use forfeited funds to help pay for increased network upgrade costs incurred by other interconnection customers in the same cluster due to a withdrawal).

on what phase the interconnection customer withdraws its interconnection request. Thus, the withdrawal penalty for an interconnection customer will be calculated as the greater of the study deposit or: (1) two times the study cost if the interconnection customer withdraws during the cluster study or after receipt of a cluster study report; (2) 5% of the interconnection customer's identified network upgrade costs if the interconnection customer withdraws during the cluster restudy or after receipt of any applicable restudy reports; (3) 10% of the interconnection customer's identified network upgrade costs if the interconnection customer withdraws during the facilities study, after receipt of the individual facilities study report, or after receipt of the draft LGIA; or (4) 20% of the interconnection customer's identified network upgrade costs if, after executing, or requesting to file unexecuted, the LGIA, the interconnection customer's LGIA is terminated before its generating facility achieves commercial operation. The table below summarizes the withdrawal penalty structure adopted herein.

Phase of Withdrawal	**Total Withdrawal Penalty (if greater than study deposit)**
Initial Cluster Study	2 times study costs
Cluster Restudy	5% of network upgrade costs
Facilities Study	10% of network upgrade costs
After Execution of, or After the Request to File Unexecuted, the	20% of network upgrade costs

Phase of Withdrawal	Total Withdrawal Penalty (if greater than study deposit)
LGIA	

792. We find that the withdrawal penalty structure adopted herein, which requires larger withdrawal penalties as the interconnection customer progresses through the interconnection process, combined with the exemptions, strikes the proper balance between enabling interconnection customers that possess imperfect information when entering into and remaining in the interconnection queue to make withdrawal decisions and deterring speculative interconnection requests from entering into and remaining in the queue when they are unlikely to be completed, to the detriment of other interconnection customers, especially when these interconnection requests are withdrawn at later stages of the interconnection process.

793. We decline to adopt the withdrawal penalty caps proposed in the NOPR because such caps would mute the economic signals that withdrawal penalties are intended to send to interconnection customers in the interconnection queue. The withdrawal penalty structure is meant to incentivize interconnection customers to withdraw from the interconnection queue upon receipt of network upgrade cost assignments that make the interconnection request commercially non-viable. However, withdrawal penalty caps would shield interconnection customers that withdraw due to higher-cost network upgrades from consequences proportional to the impact of that withdrawal, which can

drive cascading withdrawals, creating the need for restudies and leading to delays. We accordingly agree with CAISO that the withdrawal penalty caps proposed in the NOPR would disproportionately benefit interconnection requests for larger generating facilities.[1514] We find that, while withdrawal penalty caps protect interconnection customers that are allocated relatively high network upgrade costs, they offer no such commensurate protection for interconnection customers with lower network upgrade cost assignments, reflecting an imbalanced withdrawal penalty structure.

794. We also adopt and modify the proposed definition of "withdrawal penalty" in section 1 of the *pro forma* LGIP to address situations in which it may be unclear what it means to be withdrawn from the interconnection queue. Specifically, we clarify that a withdrawal penalty applies when an interconnection customer actively chooses to withdraw its interconnection request but also when its interconnection request is deemed to have been withdrawn from the interconnection queue for one reason or another, or if it otherwise does not reach commercial operation, per the terms of the *pro forma* LGIP.

795. Commenters observe that, under the NOPR proposal, interconnection customers with large projects (in terms of MW) would be subject to large withdrawal penalties.[1515] While this is true for the initial withdrawal penalty, which continues to be based on project size because it is tied to study costs, the modification to the NOPR proposal

[1514] *See* CAISO Initial Comments at 23-24.

[1515] *See* Hydropower Commenters Initial Comments at 26; rPlus Initial Comments at 5.

described above, where later withdrawal penalties are based on percentages of identified network upgrade costs, reflects the potential impact of a withdrawal on the remaining interconnection customers in a cluster. Additionally, as some commenters point out, there is typically a correlation between the size of the proposed generating facility and the relative harm to other interconnection customers from the withdrawal of the interconnection request, so we believe that basing the initial withdrawal penalty on project size is appropriate.[1516]

796. Because we modify the process for distributing withdrawal penalty funds in response to comments, as described below, transmission providers will not accumulate large amounts of funds from withdrawal penalties, and therefore Shell's concerns are moot.[1517]

797. Furthermore, we believe the proposed *pro forma* LGIP section 3.7.1.2 requirement that transmission providers post on their OASIS site, and update quarterly, the balance of withdrawal penalty revenue held by them but not yet dispersed, and the instructions of how to distribute withdrawal penalty funds contained in this provision provide sufficient transparency to help interested parties understand, monitor, and review withdrawal penalty funds. Transmission providers have substantial experience collecting and

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[1516] Avangrid Initial Comments at 20; CAISO Initial Comments at 24; Idaho Power Initial Comments at 8; National Grid Initial Comments at 26-27; PPL Initial Comments at 17.

[1517] Shell Initial Comments at 18-19.

accounting for fees assessed to customers, and we will not mandate here what accounting method they should use for the collection and tracking of withdrawal penalties.

798. With respect to the distribution of withdrawal penalty funds, we adopt the NOPR proposal to require transmission providers to use withdrawal penalty funds to fund studies and restudies conducted under the cluster study process, with modification. Specifically, we adopt a structure whereby, if interconnection customers withdraw and are subject to withdrawal penalties, the transmission provider must use the withdrawal penalty funds as follows: (1) to fund studies and restudies in the same cluster; (2) if withdrawal penalty funds remain, to offset net increases in costs borne by other remaining interconnection customers from the same cluster for network upgrades shared by both the withdrawing and non-withdrawing interconnection customers prior to the withdrawal; and (3) if any withdrawal penalty funds remain, they will be returned to the withdrawing interconnection customer.

799. We believe that using withdrawal penalty funds to reduce network upgrade cost shifts caused by withdrawals will reduce the risk that the shifted costs are so large as to cause cascading withdrawals, thus ensuring that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner. We agree with Invenergy that it is appropriate for there to be a relationship between the impact caused by the withdrawal of an interconnection request and how the withdrawal penalty funds are distributed. We also are persuaded by Invenergy, PJM, NextEra, and Southern that there are benefits to distributing withdrawal penalty funds to other interconnection customers remaining in the cluster to offset increased network upgrade costs resulting

from the withdrawal.[1518] We therefore modify the NOPR proposal and revise section 3.7.1 of the *pro forma* LGIP consistent with the discussion below.

800. In the paragraphs that follow we summarize the steps a transmission provider must follow in distributing withdrawal penalty funds, as fully detailed in section 3.7.1.2 of the *pro forma* LGIP, and we present an illustrative example.

801. Section 3.7.1.2.1 of the *pro forma* LGIP describes the transmission provider's handling of withdrawal penalty funds and the first step of distributing them to fund studies and restudies. For a single cluster, the transmission provider shall hold all withdrawal penalty funds until all interconnection customers in that cluster have: (1) withdrawn or been deemed withdrawn; (2) executed an LGIA; or (3) requested an LGIA to be filed unexecuted. Any withdrawal penalty funds collected shall first be used to fund studies for interconnection customers in the same cluster that have executed an LGIA or requested an LGIA to be filed unexecuted. Distribution of the withdrawal penalty funds for such study costs shall not exceed the total actual study costs.

802. Section 3.7.1.2.2 of the *pro forma* LGIP provides that if, after the first distribution step is complete, withdrawal penalty funds remain, the transmission provider must proceed to the second step of distributing them to offset net increases in network upgrade cost assignments driven by the withdrawal. The transmission provider will determine if the withdrawn interconnection customers, at any point in the cluster study process, shared

[1518] Invenergy Initial Comments at 27-28; NextEra Initial Comments at 27-28; PJM Initial Comments at 39; Southern Initial Comments at 20-21.

cost assignment for one or more network upgrades with any remaining interconnection customers in the same cluster based on the cluster study report, cluster restudy report(s), interconnection facilities study report, and any subsequent issued restudy report for the cluster.

803. If the transmission provider determines that withdrawn interconnection customers shared cost assignment for network upgrades with remaining interconnection customers in the same cluster, the transmission provider will calculate the remaining interconnection customers' net increase in costs (i.e., financial impact) due to a shared cost assignment for network upgrades with the withdrawn interconnection customer. It will then distribute withdrawal penalty funds as described in section 3.7.1.2.3 of the *pro forma* LGIP, depending on whether the withdrawal occurred before the withdrawing interconnection customer executed an LGIA (i.e., during the cluster study process) or after.

804. If the transmission provider determines that more than one interconnection customer in the same cluster was financially impacted by the same withdrawn interconnection customer, the transmission provider will apply the relevant withdrawn interconnection customer's withdrawal penalty to reduce the financial impact to each impacted interconnection customer based on each withdrawn interconnection customer's proportional share of the financial impact. Each interconnection customer's proportional share will be determined by either the proportional impact method if the net cost increase is related to a system network upgrade or on a per capita basis if the net cost increase is related to a substation network upgrade.

805. Section 3.7.1.2.4 of the *pro forma* LGIP details the process by which the transmission provider will provide amended LGIAs to any interconnection customers in the cluster that qualify for distribution of withdrawal penalty funds under this framework. To account for withdrawals that occurred *during the cluster study process*, the transmission provider must do the following: Within 30 calendar days of all interconnection customers in the same cluster having: (1) withdrawn or been deemed withdrawn; (2) executed an LGIA; or (3) requested an LGIA to be filed unexecuted, determine if, and to what extent, any interconnection customers qualify to have their increased network upgrade costs offset by withdrawal penalty funds and provide such interconnection customers with an amended LGIA that provides the reduction in network upgrade cost assignment and associated reduction to the interconnection customer's financial security requirements.

806. To account for withdrawals that occurred in the same cluster *after the withdrawing interconnection customer executed an LGIA, or requests the filing of an unexecuted LGIA*, the transmission provider must do the following: Within 30 calendar days of such withdrawal or termination, determine if, and to what extent, any interconnection customers qualify to have their increased network upgrade costs offset by withdrawal penalty funds and provide such interconnection customers with an amended LGIA that provides the reduction in network upgrade cost assignment and associated reduction to the interconnection customer's financial security requirements.

807. For any given withdrawal, if the transmission provider determines that there are no network upgrade cost assignments in the withdrawn interconnection customer's cluster

shared with the withdrawn interconnection customer, or if the transmission provider determines that the withdrawn interconnection customer's withdrawal did not cause a net increase in the shared cost assignment for any remaining interconnection customers in the cluster, the transmission provider must return the remaining withdrawal penalty to the withdrawn interconnection customer. Such remaining withdrawal penalties will be returned to withdrawn interconnection customers based on the proportion of each withdrawn interconnection customer's contribution to the total amount of withdrawal penalty funds collected for the cluster. The transmission provider must make such disbursement within 60 calendar days of the date on which all interconnection customers in the same cluster have either (1) withdrawn or been deemed withdrawn; (2) executed an LGIA; or (3) requested an LGIA to be filed unexecuted.

808. By way of example, assume that the transmission provider's proportional impact method identifies that interconnection customers A, B, and C in the same cluster all contribute to the need for system network upgrade A, estimated at $40 million, in the proportions of 50%, 25% and 25%, respectively. Interconnection customer C withdraws from the interconnection queue after the facilities study, but before executing, or requesting the unexecuted filing of, the LGIA and pays a withdrawal penalty of $1 million.[1519] System network upgrade A is still required for interconnection customers A

[1519] In this example, interconnection customer C paid a $1 million withdrawal penalty because it was allocated $10 million in network upgrade cost (i.e., 25% of $40 million) and withdrew after receiving the facilities study report, at which point the withdrawal penalty is 10% of the amount of network upgrades allocated to the interconnection customer.

and B, and when the transmission provider conducts the proportional impact method in the cluster restudy for the same cluster, it now determines that interconnection customer A's revised network upgrade cost allocation for system network upgrade A would increase to 67% and interconnection customer B's revised network upgrade cost allocation for system network upgrade A would increase to approximately 33%. The transmission provider would base the distribution of this interconnection customer's withdrawal penalty on the proportional impact analysis and credit 67% of the $1 million to interconnection customer A and 33% to interconnection customer B.

809. Finally, section 3.7.1.2.5 of the *pro forma* LGIP provides that if, after the first and second distribution steps are complete, some or all of an interconnection customer's withdrawal penalty remains, the transmission provider must return the balance of the withdrawn interconnection customer's withdrawal penalty funds to the withdrawn interconnection customer.

810. In response to commenter's concerns regarding the ability of transmission providers to collect withdrawal penalties from interconnection customers,[1520] we further clarify that, in addition to study deposits, transmission providers must apply commercial readiness deposits received from the interconnection customer that exceed the costs that the transmission provider has incurred, including interest calculated in accordance with

[1520] APS Initial Comments at 16; EEI Initial Comments at 8; Eversource Initial Comments at 19; MISO Initial Comments at 69.

section 35.19a(a)(2) of the Commission's regulations, toward any withdrawal penalties assessed to the interconnection customer, in accordance with *pro forma* LGIP section 3.7.

811. In response to NV Energy and Invenergy, we clarify that an interconnection customer that withdraws during any time in the interconnection process is responsible for the applicable withdrawal penalty as well as the costs incurred to perform studies up to that point, and withdrawal penalty amounts will not be applied toward incurred study costs. Additionally, in response to NV Energy, we clarify that if any portion of a generating facility proposed in an interconnection request achieves commercial operation, even if less than the original requested MW amount, the interconnection customer will not be subject to withdrawal penalties.

812. In response to Tri-State, we clarify that the phrase "regardless of any previous Withdrawal Penalty revenues received" in *pro forma* LGIP section 3.7.1.1 means that the withdrawal penalty will be calculated based on actual study costs and will exclude any credits to the study costs from penalties assessed to and received from other interconnection customers.

813. We disagree with commenters that assert that a technical conference is needed to further develop the record on withdrawal penalties before finalizing requirements in this final rule. For the reasons explained above, we believe that the record supports the reforms that we adopt herein and that their adoption is needed to ensure that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner.

7. Transition Process

a. NOPR Proposal

814. In the NOPR, the Commission proposed to revise the *pro forma* LGIP to require transmission providers to establish a transition process for moving to a first-ready, first-served cluster study process.[1521] Specifically, the Commission proposed to require transmission providers to offer existing, eligible interconnection customers the options to either enter a transitional serial interconnection facilities study or a transitional cluster study,[1522] with commercial readiness requirements, or withdraw from the interconnection queue without penalty.

815. To proceed to the transitional serial study, the Commission proposed that eligible interconnection customers (i.e., interconnection customers that have executed a facilities study agreement before the effective date of the transmission provider's compliance filing) would execute a transitional serial interconnection facilities study agreement to codify their choice.[1523] The Commission proposed that at the time of execution of such agreement, the interconnection customer would be required to provide a deposit equal to 100% of the interconnection facility and network upgrade costs allocated to the

[1521] NOPR, 179 FERC ¶ 61,194 at P 156.

[1522] In the NOPR, the Commission explained that the transmission provider would consider all interconnection requests accepted within a standard cluster study request period have equal queue priority for purposes of the cluster study. *See id.* P 67. This would be true for all interconnection requests accepted for the transitional cluster study as well, per the NOPR.

[1523] *Id.* P 158.

interconnection customer in the system impact study report. The Commission explained that if the interconnection customer's proposed generating facility reaches commercial operation, this deposit would be used toward construction costs of the same facilities.

816. The Commission further explained that if the interconnection customer withdraws, the deposit would be refunded after the final invoice for study costs and the withdrawal penalty are settled. The Commission proposed that the transitional serial study withdrawal penalty would equal nine times the study cost. The Commission also proposed that transitional serial generating facilities would be required to provide evidence of exclusive site control for the entire generating facility and any interconnection customer's interconnection facilities, as well as demonstrate commercial readiness through one of the following: (1) an executed term sheet (or comparable evidence) related to a contract for the sale of the generating facility's output or its energy/ancillary services; (2) reasonable evidence that the generating facility is included in a resource planning entity's resource plan, has received a contract via a resource solicitation process, or is being developed for a large end-use customer; or (3) a provisional LGIA that is not suspended and includes a commitment to build the generating facility. The Commission proposed that the deadline for the interconnection customer to meet all the provisions above would be 60 calendar days after the effective date of a transmission provider's compliance filing to the final rule. Finally, the

Commission proposed that the transmission provider complete transitional serial studies within 90 calendar days after the deadline for eligibility requirements to be satisfied.[1524]

817. The Commission proposed that existing interconnection customers that opt for the transitional cluster study would execute a transitional cluster study agreement to codify their choice.[1525] The Commission proposed that interconnection customers may make a one-time extension of their requested commercial operation date upon entry into the transitional cluster study, where any such extension shall not result in a commercial operation date later than December 31, 2027. The Commission proposed that the costs of this study and the identified facilities would be allocated as the costs are allocated for future cluster studies, as set forth in this final rule. The Commission also proposed that the transitional cluster would be subject to an expedited combined system impact and interconnection facilities study. The Commission explained that transitional cluster study generating facilities would be required to select ERIS or NRIS. The Commission proposed to require interconnection customers opting for a transitional cluster study to make a $5 million deposit. The Commission proposed to subject this deposit to the same conditions as the transitional serial study deposit.

818. The Commission also proposed to require interconnection customers with interconnection requests in the transitional cluster to produce evidence of exclusive site control for their entire generating facilities and demonstrate commercial readiness

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[1524] NOPR, 179 FERC ¶ 61,194 at P 158.

[1525] *Id.* P 159.

through one of the same three options described above for transitional serial studies.[1526] The Commission proposed that the deadline to satisfy these requirements would be 60 calendar days after the effective date of a transmission provider's compliance filing to the final rule. Finally, the Commission proposed that the transitional cluster study be completed by the transmission provider within 300 calendar days after the deadline for eligibility requirements to be satisfied.

819. The Commission sought comment on: (1) whether certain interconnection customers with pending interconnection requests submitted prior to the issuance of a final rule should be allowed to proceed to LGIA execution without entering the transition process; (2) whether the Commission should require transmission providers to accept any additional commercial readiness demonstrations for entry into the transition process, and whether existing interconnection customers should be permitted to enter their interconnection requests into the transitional cluster study process by posting a deposit in lieu of demonstrating commercial readiness; and (3) whether $5 million is a reasonable estimate of the costs that would be allocated to the interconnection customer via the transitional cluster study.[1527]

[1526] *Id.* P 159.

[1527] *Id.* P 160.

b. Comments

i. Comments in Support

820. A few commenters fully support the proposed transition process.[1528] For example, NRECA states that it strongly supports the proposed transition process because it fulfills the Commission's goal of ensuring an efficient way to prioritize and process interconnection requests, based on how far they have advanced through the interconnection process and their commercial readiness.[1529]

821. More commenters support the NOPR's core proposal to require transmission providers to offer interconnection customers with existing interconnection requests three options for moving forward (i.e., entering a transitional serial study, entering a transitional cluster study, or withdrawing without penalty).[1530] For example, Pine Gate asserts that, given the current interconnection queue backlogs in multiple regions, it is essential that the Commission craft a transition process that permits late-stage interconnection requests to finish the interconnection process under the existing rules, while transitioning most interconnection requests to the new cluster study process.[1531]

[1528] Affected Interconnection Customers Initial Comments at 13; Consumers Energy Initial Comments at 5; Idaho Power Initial Comments at 9; Longroad Energy Reply Comments at 16; NRECA Initial Comments at 9, 31.

[1529] NRECA Initial Comments at 31.

[1530] Clean Energy Associations Initial Comments at 42-43; ENGIE Initial Comments at 7; NARUC Initial Comments at 10; NextEra Initial Comments at 28; Ørsted Initial Comments at 13; Pine Gate Initial Comments at 35-36.

[1531] Pine Gate Initial Comments at 35-36; *see also* NextEra Initial Comments at -

822. With respect to the transitional serial study,[1532] many commenters, predominantly interconnection customers, support the proposal to provide this option to interconnection customers that have executed a facilities study agreement.[1533] AEE and Pine Gate state that this provision respects the investments made by interconnection customers based on current interconnection procedures.[1534] Similarly, Pattern Energy argues that, at the facilities study stage, an interconnection customer has relatively concrete economic expectations about its potential network upgrade obligations and should not be required to start the interconnection process over again.[1535]

823. Other commenters express qualified support for the proposal. Noting that significant investments have been made and that generating facility contracting and financing patterns have been developed based on existing tariffs, Interwest calls for a

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[1532] Note that most commenters refer to this as "proceeding to LGIA" or "proceeding to LGIA without going through the transition process," while a few use the term "transitional serial study." These terms are taken to be synonymous because the NOPR describes the transitional serial study process as permitting interconnection customers to "continue under the existing serial study process, enter into an LGIA, and interconnect." *See* NOPR, 179 FERC ¶ 61,194 at P 158.

[1533] AEE Initial Comments at 27; AES Initial Comments at 20; Affected Interconnection Customers Initial Comments at 9; Idaho Power Initial Comments at 9; Longroad Energy Reply Comments at 16; NARUC Initial Comments at 10; NextEra Initial Comments at 28; Northwest and Intermountain Initial Comments at 5; Ørsted Initial Comments at 14; Pattern Energy Initial Comments at 35; Pine Gate Initial Comments at 37; SEIA Initial Comments at 28.

[1534] AEE Initial Comments at 27; Pine Gate Initial Comments at 37.

[1535] Pattern Energy Initial Comments at 35.

structured, well-noticed transition period, to allow the market sufficient time to adjust to new processes, especially if the new process dramatically alters interconnection and cost allocation principles.[1536] Similarly, the Pennsylvania Commission agrees that a transition process is necessary to integrate the Commission's proposed interconnection queue reforms to allow individual interconnection customers the opportunity to decide, based on the newly adopted minimum interconnection parameters, whether to remain in the interconnection queue.[1537]

ii. Comments in Opposition

824. CREA and NewSun argue that the proposed transition process is unnecessary, as a first-ready, first-served cluster study process places the decision to enter a cluster in the hands of the interconnection customer regardless of whether there are previously queued interconnection requests.[1538] In a similar vein, EEI contends that it would be reasonable to require transmission providers to establish their own transition processes or to allow existing interconnection customers to proceed to LGIA execution without entering the transition process.[1539]

825. CREA and NewSun also fault the proposal to treat all interconnection requests in a transitional cluster as having a single queue priority because it fails to protect the

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[1536] Interwest Initial Comments at 6, 23-24.

[1537] Pennsylvania Commission Initial Comments at 15.

[1538] CREA and NewSun Initial Comments at 79.

[1539] EEI Initial Comments at 9.

investment expectations of interconnection customers with interconnection requests that have entered the interconnection queue.[1540] CREA and NewSun argue that the Commission has previously recognized that queue positions should be respected and either grandfathered or otherwise transitioned into a cluster study process that avoids devaluing the existing queue position. CREA and NewSun urge the Commission to modify its proposed cluster study process so that higher-queued interconnection requests are given a higher-priority than lower-queued interconnection requests. CREA and NewSun explain that this has worked in CAISO and Bonneville, which they assert uses a similar mechanism to respect queue positions in its transmission planning expansion process.

826. Shell requests that the Commission let existing processes continue for all interconnection customers that have executed a system impact study agreement or cluster study agreement because such processes, while not perfect, are functioning "well enough."[1541] Illinois Commission expresses more general concern about the time required for a transition process to be completed, noting that PJM's transition process for a recent set of interconnection queue reforms is expected to result in significant delays.[1542] Such delays, Illinois Commission contends, could prompt withdrawals and less-than-optimal use of potential new resources, which in turn would undermine state

[1540] CREA and NewSun Initial Comments at 45.

[1541] Shell Initial Comments at 37.

[1542] Illinois Commission Initial Comments at 7.

public policy goals and potentially threaten reliability. Longroad Energy similarly recommends that the Commission seek to avoid creating a situation whereby a transmission provider is forced to institute a pause on reviewing interconnection requests, similar to PJM's recent proposal to halt its review of interconnection requests for a two-year period.[1543]

iii. Comments on Specific Proposal

(a) Serial Study Eligibility and Transition Process Exceptions

827. Numerous commenters express support for one or more of the eligibility requirements proposed in the NOPR. To proceed with a transitional serial study, Affected Interconnection Customers agree that interconnection customers should provide evidence of exclusive site control, demonstrate commercial readiness, and fund 100% of their interconnection facility and network upgrade costs upfront.[1544] Affected Interconnection Customers reason that delays in processing interconnection requests occur if speculative interconnection requests without adequate funding are allowed to enter and clog the serial study process, only to drop out later and cause the need for restudies.

828. However, Bonneville, PJM, OPSI, RWE Renewables, and NextEra express concern that offering interconnection customers a serial study option may be

[1543] Longroad Energy Reply Comments at 16-17.

[1544] Affected Interconnection Customers Initial Comments at 10.

inefficient.[1545] Bonneville states that it has received 52 interconnection requests, totaling 33 GW, in the 90 days since the NOPR's issuance, and that completing existing studies under the current process could delay Bonneville's ability to implement a new cluster study process, thus diminishing its near-term benefits.[1546] OPSI calls for the Commission to analyze whether this option could materially delay the transition process, and if so, consider using a cluster study process as soon as feasible in the transition.[1547] Similarly, RWE Renewables assert that all parties should already be on notice about the pending changes, allowing for swifter movement to new processes, particularly for those that have not yet had any studies completed.[1548] NextEra argues that it is best for all interconnection customers at the same stage in the interconnection process to abide by the same transition rules rather than giving them a choice between a serial or cluster study process.[1549]

829. Several commenters suggest broadening opportunities for a transitional serial study and/or exempting certain interconnection requests from transitional study. AEE, Clean Energy Associations, and Pine Gate support allowing interconnection requests with

[1545] Bonneville Initial Comments at 14; NextEra Initial Comments at 28; OPSI Initial Comments at 6; PJM Initial Comments at 42; RWE Renewables Initial Comments at 1-2.

[1546] Bonneville Initial Comments at 14.

[1547] OPSI Initial Comments at 6.

[1548] RWE Renewables Initial Comments at 2.

[1549] NextEra Initial Comments at 28.

an executed or unexecuted facilities study agreement to proceed with a serial study.[1550] Clean Energy Associations propose serial study eligibility for any interconnection request that has a system impact study underway, provided the interconnection customer can meet commercial readiness demonstration and deposit requirements on par with what would be required at the equivalent stage of the standard cluster study process.[1551] ENGIE supports a process that exempts interconnection requests with interconnection costs of $5 million or less from a transitional study.[1552] ENGIE also proposes that interconnection requests that do not contribute to the need for network upgrades and/or do not need facilities studies be permitted to proceed to an LGIA early.

830. Cypress Creek suggests that eligibility for a transitional serial study[1553] be based on: (1) a specified interconnection queue window developed through a stakeholder process that extends to late stage interconnection requests; and (2) an objective assessment of the plotted distribution of total network upgrades (in terms of millions of dollars) to which the candidate interconnection request contributes, such that the total number of interconnection requests eligible for transitional serial and transitional cluster

[1550] AEE Initial Comments at 27; Clean Energy Associations Initial Comments at 43; Pine Gate Initial Comments at 37.

[1551] Clean Energy Associations Initial Comments at 43.

[1552] ENGIE Initial Comments at 7.

[1553] The original term used by Cypress Creek, "transitional serial cluster," is assumed to mean transitional serial study.

studies is known so transitional studies can be completed by a reasonable deadline.[1554] Cypress Creek states that the distribution curve of network upgrades will help support eligibility to those interconnection requests on the lower half of impacts. Finally, Cypress Creek suggests that the Commission establish a date by which the transitional serial process would conclude, and by which the transitional cluster process would begin. Following these transitional studies, Cypress Creek recommends that the new cluster study process commence, in lieu of the second transitional cluster proposed by the Commission. Cypress Creek argues that this more rapid transition process better balances interconnection rights of late-stage interconnection requests with the need to move to the new process compared to the proposed transition process.

(b) New Requirements on Existing Interconnection Customers

831. AEE, Invenergy, NESCOE, and Shell argue that it is wrong, or could be unfairly burdensome, to impose significant new requirements on interconnection customers that have entered and proceeded through the interconnection queue in good faith.[1555] Invenergy adds that this is especially true of interconnection customers that may have

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[1554] Cypress Creek Initial Comments at 25-26.

[1555] AEE Initial Comments at 26; Invenergy Initial Comments at 37; NESCOE - Reply Comments at 10; Shell Initial Comments at 37.

entered the interconnection queue years before the NOPR was issued.[1556] Other commenters make similar points.[1557]

832. AEE and EDF Renewables stress the importance of not disrupting or further delaying interconnection requests that are well along in the interconnection process.[1558] ACE-NY states, more broadly, that interconnection requests currently in serial interconnection queues should not be unduly harmed, adding that any transition process should not delay the commercial operation date of existing and future generating facilities.[1559]

833. Clean Energy Associations argue that transition interconnection customers, whether they be in the serial or cluster study process, should not be held to higher standards than those interconnection customers that would proceed with the regular cluster study process unless the transition process leads to an LGIA and includes only ready interconnection requests that have been delayed in the existing interconnection

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[1556] Invenergy Initial Comments at 37.

[1557] AEE Initial Comments at 26; EDF Renewables Initial Comments at 8; ACE-NY Initial Comments at 4; AEE Initial Comments at 26; EDF Renewables Initial Comments at 8; Northwest and Intermountain Initial Comments at 2, 5.

[1558] AEE Initial Comments at 26; EDF Renewables Initial Comments at 8.

[1559] ACE-NY Initial Comments at 4.

queue.[1560] Invenergy concurs with this principle, if the Commission elects to impose requirements on existing interconnection customers.[1561]

(c) Deposits

834. Several commenters object to the proposal to require that interconnection customers, at the time of execution of the transitional serial study agreement, provide a deposit equal to 100% of the interconnection facility and network upgrade costs allocated to them in the system impact study report.[1562] AEE and EDF Renewables argue that the costs assigned at the system impact study stage often vary significantly from the network upgrade costs provided at the facilities study stage.[1563] EDF Renewables also argue that the NOPR proposal is inconsistent with Order No. 2003, which specifically rejected such a proposal in favor of requiring security for discrete portions of these costs.[1564] EDF Renewables adds that requiring a full deposit imposes a real cost on interconnection customers, which typically obtain a letter of credit from a bank.

[1560] Clean Energy Associations Initial Comments at 43.

[1561] Invenergy Initial Comments at 38.

[1562] Clean Energy Associations Initial Comments at 43; Cypress Creek Initial Comments at 26; EDF Renewables Initial Comments at 9; Invenergy Initial Comments at 38; Pine Gate Initial Comments at 36; SEIA Initial Comments at 28.

[1563] AEE Initial Comments at 26-27; EDF Renewables Initial Comments at 9.

[1564] EDF Renewables Initial Comments at 9 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 596).

835. Likewise, several commenters object to the proposal to require a $5 million deposit to proceed to the transitional cluster study.[1565] Most of these commenters claim that $5 million dollars is excessive and/or arbitrary;[1566] fails to reflect the relative impact of smaller proposed generating facilities;[1567] likely is not indicative of costs across all markets;[1568] and will prompt otherwise viable interconnection requests to withdraw.[1569] With respect to the NOPR's reliance on PSCo's claim that $5 million is within the range of interconnection costs on its system, CREA and NewSun question whether PSCo intended the deposit to serve as a barrier to its competitors in the generation market.[1570] CREA and NewSun note that the three orders cited by the Commission in the NOPR mention a $5 million deposit, but none provide a reasoned decision for acceptance of this

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[1565] AEE Initial Comments at 26; Clean Energy Associations Initial Comments at 43; CREA and NewSun Initial Comments at 81; EDF Renewables Initial Comments at 9; Invenergy Initial Comments at 38; Northwest and Intermountain Initial Comments at 5; Pine Gate Initial Comments at 36.

[1566] AEE Initial Comments at 26; Clean Energy Associations Initial Comments at 43; CREA and NewSun Initial Comments at 81; EDF Renewables Initial Comments at 9; Pine Gate Initial Comments at 36.

[1567] CREA and NewSun Initial Comments at 81; EDF Renewables Initial Comments at 9.

[1568] AEE Initial Comments at 26; CREA and NewSun Initial Comments at 81; Pine Gate Initial Comments at 36.

[1569] AEE Initial Comments at 26.

[1570] CREA and NewSun Initial Comments at 81.

deposit amount.[1571] Conversely, Xcel asserts that $5 million dollars is a low estimate of costs that may ultimately be allocated to interconnection customers.[1572]

836. AEE, Invenergy, and Pine Gate recommend that the deposit for either the transitional serial facilities study agreement or transitional cluster study agreement reflect a percentage of the network upgrade costs allocated to the interconnection customer, with Invenergy recommending 20%.[1573] Northwest and Intermountain and Xcel recommend that the final rule require transmission providers to propose a deposit amount for transitional studies that is appropriate to their interconnection queue and their specific system configurations.[1574] Xcel suggests that the Commission should accept proposals that use an average of actual historical estimates of costs allocated to interconnection customers with executed LGIAs to determine the security required to enter the transitional cluster.[1575]

[1571] *Id.* at 81-82 (citing *Pub. Serv. Co. of Colo.*, 169 FERC ¶ 61,182; *Tri-State Generation & Transmission Ass'n, Inc.*, 173 FERC ¶ 61,015; *Tri-State Generation & Transmission Ass'n, Inc.,* 174 FERC ¶ 61,021 (2021).

[1572] Xcel Initial Comments at 36.

[1573] AEE Initial Comments at 26; Invenergy Initial Comments at 38; Pine Gate Initial Comments at 36.

[1574] Northwest and Intermountain Initial Comments at 5; Xcel Initial Comments at 36.

[1575] Xcel Initial Comments at 36.

(d) Commercial Readiness and Site Control

837. Idaho Power and Xcel emphasize the importance of requiring a commercial readiness demonstration to enter the transition process.[1576] Xcel argues that if a readiness demonstration is not required, unready interconnection requests may be in the study models for more than three years after they execute an LGIA and when they ultimately withdraw, which will cause delays and cascading restudies.[1577] Idaho Power asserts that commercial readiness demonstrations for interconnection customers with executed LGIAs are also critical, as their resource and network upgrades will need to be modeled in the transitional cluster study.[1578] NRECA proposes that interconnection customers that show requisite site control and commercial readiness proceed to the "front of the line" as "first-ready" in the transition cluster process without additional evaluation.[1579] Both Idaho Power and EEI recommend that interconnection customers with LGIAs, but that have suspended interconnection-related construction, be required to meet the commercial readiness requirements, with EEI also recommending that they be required to demonstrate site control.[1580]

[1576] Idaho Power Initial Comments at 9; NRECA Initial Comments at 31; Pattern Energy Initial Comments at 35; Xcel Initial Comments at 36.

[1577] Xcel Initial Comments at 36.

[1578] Idaho Power Initial Comments at 9.

[1579] NRECA Initial Comments at 31.

[1580] EEI Initial Comments at 9-10; Idaho Power Initial Comments at 9.

838. In addition to the proposed commercial readiness demonstration requirements, Affected Interconnection Customers recommend that interconnection customers also be allowed to provide evidence of (1) major equipment either contracted to purchase or owned as part of an existing equipment fleet or (2) a completed engineering package under provisional LGIAs.[1581] SEIA recommends that interconnection customers be allowed to demonstrate commercial readiness by providing a commitment to participate in RTO/ISO markets or an application for a site permit.[1582]

839. A number of commenters oppose the NOPR's proposed commercial readiness requirements, as applied to the transition process.[1583] SEIA states that the proposed requirements will be nearly impossible for an independent power producer to meet and ignore the very nature of a capacity market, which is to allow independent power producers to sell capacity into a market.[1584]

840. Several commenters support allowing a deposit in lieu of demonstrating commercial readiness, as applied to the transition process.[1585] Pattern Energy argues for this option to be available specifically for the transitional cluster study and recommends a

[1581] Affected Interconnection Customers Initial Comments at 10-11.

[1582] SEIA Reply Comments at 12.

[1583] AEE Initial Comments at 26; CREA and NewSun Initial Comments at 79; Pine Gate Initial Comments at 36; SEIA Initial Comments at 29.

[1584] SEIA Initial Comments at 28.

[1585] AEE Initial Comments at 26; EDF Renewables Initial Comments at 9; Invenergy Initial Comments at 38; Pattern Energy Initial Comments at 35.

$5 million deposit value.[1586] Pattern Energy claims that this would balance the need for interconnection customers that may have been waiting for years to have their interconnection requests studied with the need to transition to a new process. SEIA and Pine Gate recommend that a commercial readiness deposit should be the norm, not the exception, with SEIA also recommending that interconnection customers be required to provide evidence of site control.[1587] Pine Gate recommends a readiness deposit framework that requires interconnection customers to make incrementally at-risk payments throughout the interconnection process.[1588]

841. At the same time, several commenters oppose permitting deposits in lieu of demonstrating commercial readiness, as applied to the transition process.[1589] Ameren calls such deposits "opportunities for delay" that will not facilitate the interconnection of interconnection requests for which the interconnection customer has demonstrated commercial readiness.[1590] Idaho Power opposes the option because the transitional cluster study is an expedited, combined system impact and interconnection facilities study.[1591] If the Commission does allow a deposit, EEI argues that the option should

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[1586] Pattern Energy Initial Comments at 35.

[1587] SEIA Initial Comments at 29.

[1588] Pine Gate Initial Comments at 36.

[1589] Ameren Initial Comments at 19; EEI Initial Comments at 10; Idaho Power Initial Comments at 9; Xcel Initial Comments at 36.

[1590] Ameren Initial Comments at 19.

[1591] Idaho Power Initial Comments at 9.

apply only in specific circumstances, and should be sufficiently high to deter interconnection requests that are not ready from entering the transitional cluster.[1592]

(e) Withdrawal Penalties

842. Many commenters oppose the NOPR's proposed transition process withdrawal penalties.[1593] CREA and NewSun, Pine Gate, and Ørsted call the penalties harsh or draconian.[1594] Ørsted notes that offshore wind project interconnection customers with contracts awarded via a state-sponsored resource solicitation process have already spent tens of millions of dollars to secure leaseholds, conduct extensive geotechnical studies of these lease areas, and engineering studies.[1595] Given these investments, Ørsted contends that the decision to withdraw from the interconnection queue is most likely going to be based on some issue outside of the control of the interconnection customer, such as supply chain constraints, and not because the interconnection request will not go forward at some point.

[1592] EEI Reply Comments at 10.

[1593] AEE Initial Comments at 26; AES Initial Comments at 20; CREA and NewSun Initial Comments at 79; EDF Renewables Initial Comments at 8; Ørsted Initial Comments at 14; Pine Gate Initial Comments at 36; SEIA Initial Comments at 37.

[1594] CREA and NewSun Initial Comments at 79; Ørsted Initial Comments at 14; Pine Gate Initial Comments at 36.

[1595] Ørsted Initial Comments at 14.

843. AES states that withdrawal should be penalty-free if an interconnection customer decides not to move forward with a proposed generating facility during the transition.[1596] EDF Renewables asserts that a transition process should offer existing interconnection customers an opportunity to exit the interconnection queue in line with what they expected when entering.[1597] SEIA recommends that the withdrawal penalty for interconnection customers in the transitional cluster study be capped at the withdrawing interconnection request's allocation of network upgrade costs.[1598]

(f) <u>Compliance Timeline</u>

844. NRECA supports the NOPR's proposed timeline for compliance.[1599] NRECA states that the 180-day[1600] period proposed in the NOPR would be sufficient to allow interconnection customers to get their deposits, site control, and commercial readiness demonstrations in order.[1601] PPL states that transmission providers should continue moving requests to the LGIA execution stage and have interconnection customers

[1596] AES Initial Comments at 20.

[1597] EDF Renewables Initial Comments at 8.

[1598] SEIA Initial Comments at 37.

[1599] NRECA Initial Comments at 32; PPL Initial Comments at 18.

[1600] Note that the proposed deadline for transmission providers to submit a compliance filing is within 180 calendar days of the effective date of the final rule. The proposed deadline for interconnection customers to meet the requirements for transitional serial study or transitional cluster study is 60 calendar days after the Commission-approved effective date of a transmission provider's filing in compliance with this final rule.

[1601] NRECA Initial Comments at 32.

demonstrate commercial readiness as normal until the effective date of the transition process.[1602]

845. AES, CREA and NewSun, and Invenergy assert that the NOPR's proposed 60-day deadline for compliance is difficult or impossible to meet for most interconnection customers.[1603] Invenergy adds that the fact of the rulemaking's existence is insufficient to put interconnection customers on notice of potential reforms, given that any aspect of the NOPR could be modified in the final rule and be subject to variations in compliance filings.[1604] AES states that it does not oppose requiring interconnection customers to demonstrate site control and meet commercial readiness criteria but recommends that at least six months be given for compliance.[1605]

(g) Alternatives

846. Shell argues that the final rule should allow an opt-out provision for the transition process under which transmission providers can demonstrate their existing processes' efficiencies by detailing their prior performance on certain measures, such as the average

[1602] PPL Initial Comments at 18.

[1603] AES Initial Comments at 20; CREA and NewSun Initial Comments at 79; Invenergy Initial Comments at 37-38.

[1604] Invenergy Initial Comments at 37.

[1605] AES Initial Comments at 20.

duration of each interconnection study and the average length of time from submission of an interconnection request to execution of an LGIA or filing of an unexecuted LGIA.[1606]

847. In cases where the transition process is slow due to the sheer scale of change, Illinois Commission calls for an accelerated process for interconnection requests that allow states to ensure reliability and meet statutory obligations and public policy objectives.[1607] Illinois Commission adds that such a process could be accomplished in a narrowly tailored manner and would be more efficient than allowing RTOs/ISOs an extended period to clear out prior interconnection queue backlogs.

848. CREA and NewSun propose, and SEIA supports, a transitional cluster study process for transmission providers facing an otherwise unmanageable volume of interconnection requests.[1608] CREA and NewSun assert that such a process would expedite interconnection study, eliminate excessive deposits and penalties, permit withdrawals without penalty if no burden is imposed on other interconnection customers, respect queue positions and associated investment expectations of queued interconnection requests, and avoid "years of bottlenecks and market distorting problems" associated with solutions based on readiness requirements.[1609] CREA and NewSun state that this proposed process draws on Bonneville, CAISO, and MISO's current practices as

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[1606] Shell Initial Comments at 37.

[1607] Illinois Commission Initial Comments at 7-8.

[1608] SEIA Reply Comments at 12.

[1609] CREA and NewSun Initial Comments at 82, Ex. A at 4.

examples and would take an estimated 460 days to complete, incorporating four milestones with increasing deposits and two off-ramps (or decision points).[1610]

849. CREA and NewSun further propose to respect queue positions by providing a separate cluster study for existing interconnection customers that have advanced to the system impact study stage and having interconnection requests retain queue position even as they are studied in a cluster.[1611] CREA and NewSun also propose to allow interconnection customers to trade queue positions.[1612]

(h) Tariff Language

850. Southern notes that under proposed section 5.1.1.2(2) of the *pro forma* LGIP, the true-up of actual construction costs must be completed within 30 days of a generating facility achieving commercial operation, which appears to conflict with the true-up provisions in *pro forma* LGIA article 12.2 (Final Invoice), which, Southern states, provides that the true-up is due within six months.[1613] Southern requests that the Commission make these provisions consistent at six months.

iv. Requests for Flexibility and Clarification

851. Several commenters argue that a one-size-fits-all transition plan is not appropriate, given the diversity of processes currently used by transmission providers and the varying

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[1610] *Id.*, Ex. A at 3.

[1611] *Id.*, Ex. A at 2.

[1612] *Id.*, Ex., at 2-3.

[1613] Southern Initial Comments at 35.

volumes of interconnection requests in their interconnection queues.[1614] For instance, Duke Southeast Utilities references the Commission's recognition that transmission providers that already have a Commission-approved LGIP and LGIA based on a first-ready, first-served cluster study process may not need another transition process. Duke adds that requiring a second transition process would likely add confusion and potentially result in waiver requests filed with the Commission.[1615] ISO-NE states that New England does not currently suffer interconnection queue backlogs to the same extent as other regions, and transition provisions could have a significant impact on interconnection requests that are currently proceeding through the existing interconnection process.[1616] WAPA claims that it needs sufficient flexibility to develop new programs within its existing appropriations (or to seek additional appropriations or spending authority) and to

[1614] Ameren Initial Comments at 19; Avangrid Initial Comments at 8; Bonneville Initial Comments at 13; CAISO Initial Comments at 24; Duke Southeast Utilities Initial Comments at 11; EEI Initial Comments at 10; Indicated PJM TOs Reply Comments at 42; Invenergy Initial Comments at 39; ISO-NE Initial Comments at 33; MISO Initial Comments at 70; NARUC Initial Comments at 10-11; National Grid Initial Comments at 28; NEPOOL Initial Comments at 14; NYISO Initial Comments at 12; NYTOs Initial Comments at 21; WAPA Initial Comments at 8-9; *see also* Invenergy Initial Comments at 41 (asserting that, while many of the NOPR proposals should be prospective only, affected systems reform should apply immediately to all pending requests and active studies).

[1615] Duke Southeast Utilities Initial Comments at 11.

[1616] ISO-NE Initial Comments at 33-34.

accommodate federal contracting timelines (because it hires contractors to conduct facilities studies).[1617]

852. CAISO, Duke Southeast Utilities, and Invenergy call on the Commission to permit transmission providers in regions that already use a first-ready, first-served cluster study process to minimize or omit a transition process.[1618] CAISO recommends that transmission providers be permitted to propose just and reasonable effective dates for each reform.[1619] CAISO adds that it anticipates that most reforms should be effective with the beginning of the next cluster study after a compliance filing is approved, but some reforms could be implemented for existing interconnection requests in the queue, especially for interconnection customers that may not have executed an LGIA. Conversely, Tri-State states that a transition period will be necessary, even for those transmission providers already employing a first-ready, first-served cluster study process, due to changes beyond the overarching structure of the interconnection queue, such as a requirement for 100% site control.[1620]

[1617] WAPA Initial Comments at 8-9.

[1618] CAISO Initial Comments at 25.

[1618] *Id.*; Duke Southeast Utilities Initial Comments at 11; Invenergy Initial Comments at 39.

[1619] CAISO Initial Comments at 25.

[1620] Tri-State Initial Comments at 17.

853. Several commenters ask the Commission to let transmission providers establish their own transition plans.[1621] MISO notes that this previously occurred after the 2008 interconnection queue technical conference, where transmission providers were able to propose their own transition plan in adopting a first-ready, first-served model.[1622] Ameren, National Grid, and NEPOOL call for RTOs/ISOs, in particular, to be allowed flexibility to develop a transition process with input from stakeholders.[1623] Avangrid notes that determining an equitable and achievable transition plan was among the most challenging aspects of the stakeholder process that led to PJM's recent interconnection queue reform filing and asserts that other regions should have the chance for similar deliberations.[1624] NYTOs argue that transmission providers should be allowed to propose: (1) setting an effective date for new interconnection requests that will be subject to the new cluster study process; (2) establishing an approach for the existing interconnection queue to be seen through to completion; and (3) determining a high-level

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[1621] Ameren Initial Comments at 19; Avangrid Initial Comments at 37; MISO Initial Comments at 70; National Grid Initial Comments at 28-29; NEPOOL Initial Comments at 14; NESCOE Reply Comments at 10; NYTOs Initial Comments at 21-22.

[1622] MISO Initial Comments at 70.

[1623] Ameren Initial Comments at 19; National Grid Initial Comments at 28; NEPOOL Initial Comments at 14.

[1624] Avangrid Initial Comments at 8, 36-37.

process, including a high-level time frame for updating tariffs, if the proposed reforms are approved.[1625]

854. Several commenters request that the Commission clarify how the NOPR's proposed transition process relates to PJM's transition process accepted as part of its recent interconnection queue reforms.[1626] OPSI requests that the final rule not extend any transition process beyond what PJM proposed.[1627] Indicated PJM TOs request that the Commission allow PJM to implement its carefully negotiated transition process to a first-ready, first-served cluster study process.[1628] PJM suggests that the Commission hold in abeyance any compliance filing obligations in this proceeding until PJM has completed its proposed transition process.[1629] PJM argues that this would be in keeping with the Commission's statement that it will review any filings that result from transmission provider interconnection queue reform efforts "based on the record before us in those proceedings and not based on whether they comply with the proposed reforms in this NOPR."[1630] PJM also asserts that, given the size of its interconnection queue backlog,

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[1625] NYTOs Initial Comments at 21-22.

[1626] Indicated PJM TOs Initial Comments at 34; OPSI Initial Comments at 7; Pennsylvania Commission Initial Comments at 15; PJM Initial Comments at 42; *see also PJM Interconnection, L.L.C.,* 181 FERC ¶ 61,162 at PP 60-69.

[1627] OPSI Initial Comments at 7.

[1628] Indicated PJM TOs Initial Comments at 34.

[1629] PJM Initial Comments at 42.

[1630] *Id.* at 42-43 (citing NOPR, 179 FERC ¶ 61,194 at P 6).

allowing interconnection customers the option of a transitional serial study process will delay implementation of PJM's cluster study process by several years and create uncertainty regarding that process.[1631] PJM emphasizes that elsewhere in the NOPR, the Commission acknowledges the importance of allowing transmission providers to clear their interconnection queue backlogs quickly.[1632]

c. **Commission Determination**

855. We adopt the NOPR proposal to modify section 5 of the *pro forma* LGIP to establish a transition process for moving to the first-ready, first-served cluster study process adopted in this final rule from the existing first-come, first-served serial study process. Specifically, we adopt the NOPR proposal to require transmission providers to offer existing interconnection customers up to three transition options, depending on which phase of the serial study process their interconnection requests are in: (1) a transitional serial study comprised of a facilities study (i.e., a transitional serial interconnection facilities study), (2) a transitional cluster study comprised of a clustered system impact study and individual facilities studies, or (3) withdrawal from the interconnection queue without penalty. We also adopt definitions for the reports issued in association with options (1) and (2), respectively (i.e., a transitional serial interconnection facilities study report and a transitional cluster study report). As discussed below, regarding eligibility for the transitional serial study, we modify the

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[1631] *Id.* at 43.

[1632] PJM Reply Comments at 8-9.

NOPR proposal to require transmission providers to offer the transitional serial study option to interconnection customers that have been tendered a facilities study agreement, even if they have not yet executed that agreement, as of 30 calendar days after the filing date of the transmission provider's initial filing to comply with this final rule. Similarly, regarding eligibility for the transitional cluster study, we modify the NOPR proposal to require transmission providers to offer the transitional cluster study option to interconnection customers with an assigned queue position as of 30 calendar days after the filing date of the transmission provider's initial filing to comply with this final rule. We also adopt the NOPR proposals for transition process deposits, withdrawal penalties, and deadlines. We decline to adopt the proposal to impose a commercial readiness demonstration requirement and adopt, with modification, the NOPR proposal for site control requirements.

856. We concur with commenters that, given current interconnection queue backlogs in multiple regions, it is essential that the Commission craft a transition process. Doing so will give interconnection customers, along with other market participants, time to adjust to new processes and requirements. We note that many responsive commenters support the proposed three options and, in particular, support providing interconnection customers at the facilities study stage the option for a transitional serial study.[1633] We

[1633] Clean Energy Associations Initial Comments at 42-43; Consumers Energy Initial Comments at 5; ENGIE Initial Comments at 7; Longroad Energy Reply Comments at 16; NARUC Initial Comments at 10; NextEra Initial Comments at 28; Ørsted Initial Comments at 13; Pine Gate Initial Comments at 35-36.

concur with NRECA that the NOPR's proposed transition process will create an efficient way to prioritize and process interconnection requests, based on how far they have advanced through the interconnection process and their level of commercial readiness. We further find that the transition process, as adopted herein, appropriately balances the need to move expeditiously to the new cluster study process with the need to respect the investments and expectations of interconnection customers at an advanced stage in the existing interconnection process.[1634]

857. We disagree with commenters that contend that the NOPR's proposed transition process is unnecessary, should be optional, or poses an undue risk of delay. As stated in the NOPR and affirmed in our findings in Section II of this final rule, we believe that interconnection queue backlogs exist throughout the country, in part, because the *pro forma* LGIP creates an incentive for interconnection customers to submit multiple interconnection requests for a given potential generating facility and remain in the interconnection queue to determine which of those interconnection requests has the lowest costs to interconnect.[1635] Given this, simply moving to the new cluster study process, as CREA and NewSun suggest, risks creating large initial clusters, which may prevent interconnection customers from being able to interconnect in a reliable, efficient, transparent, and timely manner. Similarly, if transmission providers only used serial study processes to transition, it could put existing interconnection requests at greater risk

[1634] *See e.g.*, *Pub. Serv. Co. of Colo.*, 169 FERC ¶ 61,182.

[1635] NOPR, 179 FERC ¶ 61,194 at PP 24-35.

of cascading withdrawals that would delay the adoption of standard cluster study processes. With respect to concerns that a transition process could introduce delays, we note that the serial study portion of the transition process is limited to 90 calendar days, after which point the transitional cluster study commences.

858. We decline requests to modify the proposed transitional cluster study process to give higher-queued interconnection requests a higher queue position than lower-queued interconnection requests. As stated above, to address the interconnection queue backlogs that currently exist, it is necessary to move the bulk of existing interconnection requests to the cluster study process, and as such, interconnection requests studied in the same cluster have equal queue priority to avoid undue discrimination.

859. We also decline calls to modify the NOPR proposal to require that: (1) interconnection customers electing the transitional serial study must provide a deposit equal to 100% of the interconnection facility and network upgrade costs allocated to the interconnection customer in the system impact study; and (2) interconnection customers electing the transitional cluster study must provide a deposit equal to $5 million. As noted earlier, the transition process is anticipated to involve more interconnection customers than standard annual clusters (due to existing interconnection queue backlogs), which greatly increases the risk of late-stage withdrawals. Adopting deposit requirements for the transitional studies higher than those adopted for the cluster study process will help to ensure that the transitional process is used by interconnection customers that intend to proceed with their proposed generating facilities. In response to arguments that the proposed deposit amounts are arbitrary and/or excessive, we note that

they are based on expected costs to the extent practicable and that only a portion of these deposits are ultimately at-risk. That is, the withdrawal penalty is set at nine times the study cost, as discussed below, with the remainder of deposits to be refunded.[1636] We also note that existing interconnection customers that are currently in an interconnection queue can opt to withdraw their interconnection requests without penalty and wait for the first standard cluster study with associated lower deposit requirements. Finally, with respect to EDF Renewable's claim that the transitional serial study deposit conflicts with the Commission's intentions in Order No. 2003, we find that the heightened need to avoid late-stage withdrawals during the transition process—a need that the Commission could not have anticipated in Order No. 2003—warrants the transitional use of this requirement for the transitional serial study.

860. We adopt the NOPR proposal that the transitional study withdrawal penalty should equal nine times the study cost. The withdrawal penalty plays an important role in deterring speculative interconnection requests in both the standard cluster study and the transition process. We disagree with commenters that call for a lower penalty to apply during the transition process, given that the risk of withdrawals is heightened during the transition process. With respect to Ørsted's contention that offshore wind developers will likely withdraw interconnection requests solely due to circumstances beyond their control, we note that, regardless of the cause, a withdrawal may cause harm to other

[1636] *See supra* Section III.A.7.a. Also, as one indicator of study costs, NV Energy states that, on average, it spends between $80,000 and $100,000 between the clustered system impact study and facilities studies. *See supra* Section III.A.6.a.

interconnection customers in the transition process. Thus, we find it appropriate to impose penalties on those that choose to withdraw notwithstanding that withdrawal may at times be due to circumstances beyond the interconnection customer's control. Interconnection customers will bear the risk of withdrawal penalties and consider that risk in deciding whether to elect to join a transition process.

861. We recognize that some transmission providers have existing cluster studies in progress and others have Commission-approved transition plans in progress. We emphasize that the provisions of this final rule are not intended to interfere with the timely completion of those in-progress cluster studies and transition processes. With respect to concerns about duplicative transition processes, we clarify that transmission providers that have already adopted a cluster study process or are currently undergoing a transition to a cluster study process will not be required to implement a new transition process.

862. We are not persuaded by commenters' requests to permit transmission providers to establish their own transition plans. Transmission providers would likely require months-to-years to develop and execute their own transition plans, given the need for stakeholder dialogue and internal approval, followed by Commission review and approval. We find that the benefits of moving forward with an efficient, standardized transition process outweigh the potential benefits of relying on tailor-made transition processes developed by each transmission provider and its stakeholders.

863. Likewise, we decline to adopt any of the alternatives put forth by commenters. We are not persuaded by Shell's proposal to allow transmission providers to "opt-out" of

the transition process based on their prior performance. We view the existing serial study process as inherently more prone to cascading withdrawals and delays, and thus ill-suited to a transition period intended to set the stage for a standard cluster study process. We view the Illinois Commission's proposal for an accelerated process (for interconnection requests related to states' objectives) in regions that may propose a lengthier transition process timeline, as more appropriately addressed by transmission providers in individual compliance filings. And, given the need for even more stringent requirements in a transition process discussed earlier, we view CREA and NewSun's proposal to use progressively increasing deposits, during a transition process, as inherently ill-suited to address major interconnection queue backlogs.

864. Finally, we decline calls to modify the NOPR proposal to require interconnection customers to meet transitional serial study eligibility requirements in 60 days after the Commission-approved effective date of a transmission provider's filing in compliance with this final rule. Given that we do not adopt the proposed commercial readiness demonstration requirements, we find that the 60-calendar day deadline provides interconnection customers with sufficient time to adjust to the new requirements, i.e., to choose a transition option and, depending on the option chosen, demonstrate site control and provide a deposit. Furthermore, we concur with NRECA that this period will be augmented, in practice, by the 90-calendar day period afforded to transmission providers to submit their compliance filings.[1637]

[1637] *See infra* Section IV.C.

i. Transition Process Eligibility and Exceptions

865. As stated above, we modify the NOPR proposal regarding the eligibility for the transitional serial study and transitional cluster study.[1638] Any interconnection customer that has been tendered a facilities study agreement as of 30 calendar days after the filing date of the transmission provider's initial filing to comply with this final rule (even if it has not yet executed that agreement) may opt to proceed with a transitional serial study or withdraw its interconnection request without penalty. Transmission providers are required to tender an LGIA, pursuant to the requirements of section 11 of the *pro forma* LGIP, to any interconnection customer that has received a final facilities study report before the transmission provider commences transitional serial studies. Any interconnection customer that has an assigned queue position as of 30 calendar days after the filing date of the transmission provider's initial filing to comply with this final rule may opt to proceed with a transitional cluster study or withdraw its interconnection request without penalty.

866. We find that an earlier eligibility cut-off for the transitional studies will allow the transitional studies to begin sooner, which in turn, will allow transmission providers and interconnection customers to benefit from the Commission's new cluster study process sooner. Further, we consider this modification appropriate because interconnection customers will have 120 calendar days after the publication of this final rule in the Federal Register to achieve eligibility for the transition process (90 calendar days for

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[1638] *See supra* Section III.A.7.c.

transmission providers to submit compliance filings, plus the 30-calendar day eligibility cut-off).

867. Additionally, we modify the NOPR proposal to require the transmission provider to tender the appropriate transitional study agreements (serial and/or cluster as applicable) to eligible interconnection customers no later than the Commission-approved effective date of the transmission provider's compliance filing with this final rule. We find that this requirement will help ensure that interconnection customers are informed about their eligibility for the transitional studies (including the associated requirements and deadlines) in a timely manner.

868. Transmission providers are not required to tender transitional study agreements to interconnection customers that submit an interconnection request after the 30-calendar day eligibility cut-off described above. Interconnection customers that submit an interconnection request after the 30-calendar day eligibility cut-off will be required to pay for any studies conducted by the transmission provider under its existing tariff (as required by *pro forma* LGIP section 13.3), and their interconnection requests will not be allowed to enter the transition process, although they may enter their interconnection requests in the transmission provider's first standard cluster study, provided that they meet the new requirements for interconnection requests by the close of the first cluster request window.

869. We are persuaded by commenters' suggestion to require transmission providers to offer the transitional serial study option to interconnection customers that have been tendered a facilities study agreement, even if they have not yet executed that agreement,

as of 30 calendar days after the filing date of the transmission provider's initial filing to comply with this final rule, and we modify the NOPR proposal accordingly. We find that interconnection requests at this point in the interconnection process are at an equivalent point as those interconnection requests for which interconnection customers have executed a facilities study agreement, as in both cases, the transmission provider has completed the system impact study but has not yet commenced the facilities study. We are not persuaded by commenters to extend the option for transitional serial study to interconnection requests at earlier stages in the interconnection process, as such modifications may undermine the ability of the proposed reforms to accelerate interconnection queue processing and could delay the transition to the new, more efficient cluster study process. We disagree with the proposal to exempt from the transition process interconnection requests that appear, based on a feasibility study, to require limited or no network upgrades. The results of this feasibility study may no longer be accurate depending on which higher-queued interconnection customers remain in the interconnection queue after the transition date.

ii. <u>Commercial Readiness and Site Control</u>

870. We decline to adopt the proposed commercial readiness demonstration options for transitional studies for the same reasons that we are not adopting those options for cluster studies going forward, as discussed above. We adopt with modification the NOPR's proposed site control requirements. Specifically, we require interconnection customers electing a transitional study, regardless of whether they select the transitional serial study or the transitional cluster study, to demonstrate 100% site control for their proposed

generating facilities. We find that such a requirement will provide further assurance that such interconnection customers are ready to proceed to construction. We modify the NOPR proposal by declining to require that interconnection customers that choose to proceed with a transitional serial interconnection facilities study must also demonstrate 100% site control for any interconnection customer's interconnection facilities because such a requirement would be overly burdensome for interconnection customers, in addition to the other requirements we are adopting elsewhere in this final rule. Further, we find that this requirement is not needed to ensure that such interconnection customers are ready to proceed to construction.

iii. <u>Tariff Language</u>

871. We agree with Southern's recommendation to align timelines for truing up construction costs in the proposed *pro forma* LGIP section 5.1.1.2(2) and current, unmodified by this final rule, *pro forma* LGIA article 12.2 (Final Invoice) by making these provisions consistent at six months, and we modify the NOPR proposal accordingly. We agree with Southern that consistent timelines for truing up construction costs will provide clarity and certainty for interconnection customers.

B. Reforms to Increase the Speed of Interconnection Queue Processing

1. Elimination of the Reasonable Efforts Standard

a. Need for Reform and NOPR Proposal

872. As the Commission explained in the NOPR, the *pro forma* LGIP does not require transmission providers to meet deadlines for conducting interconnection studies.[1639] Rather, transmission providers are only required to use "reasonable efforts" to complete interconnection studies on time.[1640] "Reasonable efforts" are defined as "actions that are timely and consistent with Good Utility Practice and are substantially equivalent to those a Party would use to protect its own interests."[1641] There are no explicit consequences in the *pro forma* LGIP for transmission providers that fail to meet their study deadlines.

873. In the NOPR, the Commission preliminarily found that the use of the reasonable efforts standard for transmission providers to complete interconnection studies resulted in Commission-jurisdictional rates that were unjust and unreasonable because: (1) the timely provision of interconnection service was critical to maintaining just and reasonable rates; (2) the data collected pursuant to Order No. 845 demonstrated that the failure to timely complete interconnection studies was a significant nationwide problem, even for transmission providers that had implemented other interconnection reforms; and (3) the reasonable efforts standard did not provide a meaningful incentive for

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[1639] NOPR, 179 FERC ¶ 61,194 at P 28.

[1640] *See pro forma* LGIP sections 2.2, 6.3, 7.4, 8.3.

[1641] Order No. 2003, 104 FERC ¶ 61,103 at P 67; *pro forma* LGIP section 1.

transmission providers to complete their interconnection studies within the deadlines established in their tariffs.[1642]

874. The Commission proposed to revise the *pro forma* LGIP to eliminate the reasonable efforts standard for transmission providers completing interconnection studies and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet study deadlines.[1643] Specifically, the Commission proposed to require transmission providers that do not complete a cluster study, cluster restudy, facilities study, or affected system study by the deadline specified in the *pro forma* LGIP to pay a penalty of $500 per each business day that the study is late, except in situations where *force majeure* applies. The Commission proposed that those penalties would be distributed to the delayed interconnection customers on a pro rata basis to offset their study costs. Consistent with other penalties, the Commission proposed that such penalties would not be recoverable in transmission rates.[1644]

875. The Commission also proposed to cap penalties at 100% of the total study deposit received for the late study to provide a safeguard against overly large penalties that may

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[1642] NOPR, 179 FERC ¶ 61,194 at PP 165-167 (citing May Joint Task Force Tr. 89:6-25 (Thad LeVar) (encouraging the Commission to examine "appropriate consequences to the transmission providers when they [do not] comply with the tariffs," including by missing study deadlines)).

[1643] *Id.* P 168.

[1644] *Id.* P 169.

be considered punitive.[1645] The Commission further proposed that no financial penalties on transmission providers that fail to meet study deadlines would be assessed until one cluster study cycle (that is not a transitional study cycle) after the Commission-approved effective date for implementing the reforms proposed in the NOPR. Additionally, the Commission proposed a 10-business day grace period such that no penalties would be assessed for a study that is delayed by 10 business days or less; for studies that are delayed by more than 10 business days, the penalty would be calculated based on the first business day the study was late. Further, the Commission proposed to permit the transmission provider to extend the deadline for a particular study by 30 business days by mutual agreement of the transmission provider and all interconnection customers in the relevant study. Finally, the Commission proposed to require transmission providers to post to their OASIS or a public website on a quarterly basis the total amount of such penalties from the previous quarter and the highest amount of such penalties paid to a single interconnection request from the previous quarter.

876. The Commission acknowledged that the application of penalties for late interconnection studies in the context of RTOs/ISOs may raise several unique issues.[1646] However, consistent with the Commission's findings in Order No. 890,[1647] the

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[1645] *Id.* P 170.

[1646] *Id.* P 171.

[1647] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, 72 FR 12,226, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008),

Commission explained that penalties are appropriate in certain circumstances to incentivize compliance with tariff deadlines, notwithstanding the RTO's/ISO's status as a not-for-profit entity. To ensure that RTOs/ISOs would be able to pay any such penalties, the Commission proposed to require RTOs/ISOs to propose tariff provisions that would require the RTO/ISO to submit requests to recover the costs of specific interconnection study penalties under FPA section 205. The Commission explained that, similar to the ability of RTOs/ISOs to seek to directly assign monetary penalties for violations of reliability standards to other responsible entities, RTOs/ISOs could include a provision that the RTO/ISO may make an FPA section 205 filing seeking to allocate such penalties to the appropriate transmission owner that is responsible for, or contributed to, the delay.[1648] However, the Commission sought comment on whether there was a more appropriate method for assigning such penalties in RTOs/ISOs. More generally, the Commission sought comment on whether penalties would effectively incentivize more timely completion of interconnection studies in RTOs/ISOs, and/or whether monetary penalties could have adverse consequences (e.g., compromising accuracy or increasing waiver requests as transmission providers strive to meet deadlines).

877. Additionally, the Commission sought comment on: (1) the proposed penalty structure, including whether the penalty amount for a cluster study should be $500 per

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order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[1648] NOPR, 179 FERC ¶ 61,194 at P 172.

business day or whether an approach that accounts for the number of interconnection customers affected, such as $100 per business day per customer in the delayed study, would be more appropriate; (2) how and when the Commission should require transmission providers to communicate to interconnection customers the status of studies that may be delayed; (3) whether to include exceptions to the penalty other than *force majeure*, and if so, what those exceptions should be; and (4) whether Commission staff should issue periodic reports summarizing the status of transmission providers' interconnection queues and timeliness of interconnection studies based on information collected through existing reporting requirements, and whether this periodic report should be in addition to or a substitute for the proposed monetary penalties discussed above.[1649]

b. <u>Comments</u>

i. <u>Comments in Support</u>

878. Many commenters support the NOPR proposal to eliminate the reasonable efforts standard and establish firm interconnection study deadlines by imposing financial penalties when transmission providers fail to meet study deadlines.[1650] Multiple

[1649] *Id.* P 173.

[1650] ACE-NY Initial Comments at 11-12; ACE-NY Reply Comments at 2; ACORE Initial Comments at 4; Affected Interconnection Customers Initial Comments at 23-25; CESA Initial Comments at 11; Clean Energy Associations Initial Comments at 43; Clean Energy States Initial Comments at 9; Consumers Energy Initial Comments at 5; CREA and NewSun Initial Comments at 83; CREA and NewSun Reply Comments at 56; Cypress Creek Initial Comments at 23; ELCON Initial Comments at 7; EPSA Initial Comments at 10-11; Evergreen Action Initial Comments at 2; Fervo Energy Initial Comments at 5; Fervo Energy Reply Comments at 7; Google Initial Comments at 5; Google Reply Comments at 3, 5; Illinois Commission Initial Comments at 9; Individual Signatories Initial Comments at 1; Interwest Initial Comments at 8; Invenergy Initial

commenters explain that interconnection studies are often substantially delayed, which creates uncertainty and risk in the process of bringing new generating facilities online,[1651] and ultimately results in an unreasonable market barrier for new generating facilities.[1652] NARUC contends that the timely provision of interconnection service is critical to maintaining just and reasonable rates.[1653]

879. Some commenters argue that the interconnection queue backlogs indicate that the reasonable efforts standard has not been effective in ensuring timely access to the transmission system for new generating facilities[1654] nor in imposing consequences when transmission providers fail to meet study deadlines.[1655] Some commenters argue that the

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Comments at 29-30; Iowa Commission Initial Comments at 5; Navajo Utility Initial Comments at 12; New Jersey Commission Initial Comments at 13-14; New Jersey Commission Reply Comments at 1; Northwest and Intermountain Initial Comments at 14; Ørsted Initial Comments at 14; Pine Gate Initial Comments at 38; Public Interest Organizations Initial Comments at 33; SEIA Initial Comments at 30; TAPS Initial Comments at 3; UMPA Initial Comments at 6-7.

[1651] ELCON Initial Comments at 7; EPSA Initial Comments at 11; Fervo Energy Initial Comments at 5; NARUC Initial Comments at 13-14; Navajo Utility Initial Comments at 12; SEIA Initial Comments at 33.

[1652] Pennsylvania Commission Initial Comments at 4; *see also* AEE Reply Comments at 21, 30; Fervo Energy Reply Comments at 7; Public Interest Organizations Initial Comments at 33 (explaining that the slow pace of interconnection has discouraged incorporation of new generation and stunted the transition of the transmission system).

[1653] NARUC Initial Comments at 13-14.

[1654] AEE Reply Comments at 20-21; Clean Energy Associations Initial Comments at 43; CREA and NewSun Initial Comments at 84; Iowa Commission Initial Comments at 5; New Jersey Commission Reply Comments at 3; Public Interest Organizations Initial Comments at 34.

[1655] ACE-NY Reply Comments at 3; Affected Interconnection Customers Initial

Order No. 845 reporting data supports the conclusion that the reasonable efforts standard has failed to ensure transmission providers complete interconnection studies on time.[1656] AEE argues that the broad definition of "reasonable efforts" presents a high bar to prove that interconnection study delays were unreasonable.[1657]

880. Some commenters assert that the reasonable efforts standard results in an insufficient allocation of transmission provider resources to process the interconnection queue[1658] and that the risk of penalties will provide a needed incentive for transmission providers to complete interconnection studies on time.[1659] Some commenters argue that penalizing transmission providers is appropriate because they control the staffing and

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Comments at 23; CREA and Newsun Initial Comments at 83; EPSA Initial Comments at 10; Fervo Energy Initial Comments at 5; Pennsylvania Commission Initial Comments at 2.

[1656] ACE-NY Initial Comments at 11-12; AEE Reply Comments at 18; Affected Interconnection Customers Initial Comments at 23-24; Pennsylvania Commission Initial Comments at 2-3; UMPA Initial Comments at 6-7.

[1657] AEE Initial Comments at 28.

[1658] ELCON Initial Comments at 7; Fervo Energy Initial Comments at 5; Invenergy Initial Comments at 29-30; Northwest and Intermountain Initial Comments at 14; *see also* Clean Energy Associations Initial Comments at 43-44; NARUC Initial Comments at 14; SEIA Initial Comments at 33.

[1659] ACE-NY Initial Comments at 12; ACE-NY Reply Comments at 3; ELCON Initial Comments at 7; EPSA Initial Comments at 11; Evergreen Action Initial Comments at 2-3; Fervo Energy Initial Comments at 5; Google Initial Comments at 16; Individual Signatories Initial Comments at 1; New Jersey Commission Reply Comments at 2; Northwest and Intermountain Initial Comments at 14; Pine Gate Initial Comments at 38; Public Interest Organizations Initial Comments at 34; SEIA Initial Comments at 33; TAPS Initial Comments at 3.

study process and are in the best position to ensure that studies are timely and accurate.[1660] CREA and NewSun assert that the volume of interconnection requests is unlikely to decrease, so transmission providers need to ensure that they hire adequate staff to meet this need.[1661] Google cautions against taking "implicit threats of reduced cooperation or assertions that transmission providers cannot do any better" seriously, noting that any major reform to interconnection processes will entail growing pains.[1662] AEE argues that some transmission providers have improved their generator interconnection process, which underscores that it is feasible to hold all transmission providers to higher standards.[1663]

881. Some commenters point out that the NOPR proposal resolves an imbalance between interconnection customers, which are held to strict deadlines, and transmission providers, which are currently not required to meet study deadlines.[1664] Some commenters assert that the proposed penalties complement the stricter financial and

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[1660] Invenergy Initial Comments at 30; SEIA Initial Comments at 32; *see also* Iowa Commission Initial Comments at 5-6 ("RTOs/ISOs need to prioritize interconnection studies and need to hold their employees and/or outside entities responsible for delays").

[1661] CREA and NewSun Reply Comments at 56.

[1662] Google Reply Comments at 4.

[1663] AEE Reply Comments at 26.

[1664] ACE-NY Initial Comments at 12; CREA and NewSun Initial Comments at 83-84; ELCON Initial Comments at 8; Fervo Energy Reply Comments at 7-8; Pennsylvania Commission Initial Comments at 2-3; Public Interest Organizations Reply Comments at 10; SEIA Reply Comments at 13.

readiness requirements that the NOPR proposed to apply to interconnection customers[1665] or that the firm study deadlines and penalty structure are necessary to ensure that the other NOPR proposals are successful.[1666]

882. Multiple commenters note that long interconnection delays have economic costs for consumers, so transmission providers should also face economic costs for failing to meet deadlines.[1667] Navajo Utility asserts that interconnection delays prevent it from using 100 MW of transmission rights that it was granted through settlement, which leaves it with an obligation to pay for transmission rights without the ability to use them.[1668]

[1665] AEE Reply Comments at 19-21; APPA-LPPC Initial Comments at 21; Clean Energy Associations Initial Comments at 43.

[1666] ACE-NY Initial Comments at 12; EPSA Initial Comments at 11; Evergreen Action Initial Comments at 2-3; Fervo Energy Initial Comments at 5; Individual Signatories Initial Comments at 1; New Jersey Commission Reply Comments at 2; Pine Gate Initial Comments at 38; SEIA Initial Comments at 33.

[1667] AEE Reply Comments at 18, 30; Consumers Energy Initial Comments at 7 (explaining that interconnection delays could create additional costs to end-use customers because LSEs may invest in continued operation of existing assets set to retire while new generating facilities are delayed); Evergreen Action Initial Comments at 2; Interwest Initial Comments at 8; Iowa Commission Initial Comments at 5-6 (asserting that "[d]elayed studies result in denial of likely low-cost generation to consumers"); Navajo Utility Initial Comments at 12 (explaining that study delays postpone important generation, tax revenue, and construction jobs for Navajo Nation); Northwest and Intermountain Initial Comments at 14; Public Interest Organizations Reply Comments at 10; SEIA Initial Comments at 32; SEIA Reply Comments at 13.

[1668] Navajo Utility Initial Comments at 12.

ii. **Comments in Opposition**

883. Many commenters, particularly transmission providers, oppose the NOPR proposal to eliminate the reasonable efforts standard and impose financial penalties on transmission providers for late studies.[1669] Further, some commenters assert that the Commission cannot support a statutory finding under FPA section 206 to justify the NOPR proposal[1670] or that the NOPR proposal is not based on substantial evidence and fails to consider important aspects of the problem.[1671]

884. Many commenters argue that it is inequitable to penalize transmission providers for study delays because those delays are largely due to factors outside the transmission provider's control, including high volumes of speculative interconnection requests, a

[1669] AECI Initial Comments at 6; AEP Initial Comments at 25-29; Alliant Energy Initial Comments at 6; Ameren Initial Comments at 20-21; Avangrid Initial Comments at 9; Bonneville Initial Comments at 15; Dominion Initial Comments at 34; EEI Initial Comments at 14-15; Indicated PJM TOs Initial Comments at 5, 36; Longroad Energy Reply Comments at 14; MISO Initial Comments at 13, 71; MISO TOs Initial Comments at 14; NextEra Initial Comments at 6, 29-30; North Dakota Commission Initial Comments at 5; NYISO Initial Comments at 25-26; NYTOs Reply Comments at 2; Omaha Public Power Initial Comments at 11; OMS Initial Comments at 15; Pacific Northwest Utilities Initial Comments at 9; PacifiCorp Initial Comments at 32-34; PG&E Initial Comments at 3-5; PJM Initial Comments at 7, 55; PPL Initial Comments at 19; Puget Sound Initial Comments at 9; SDG&E Reply Comments at 1; Southern Initial Comments at 5; SPP Initial Comments at 11; Tri-State Initial Comments at 17-18; U.S. Chamber of Commerce Initial Comments at 9; Vermont Electric and Vermont Transco Initial Comments at 2; WAPA Initial Comments at 10; WIRES Initial Comments at 9-10; Xcel Initial Comments at 38.

[1670] Indicated PJM TOs Initial Comments at 38.

[1671] Dominion Reply Comments at 20; MISO TOs Initial Comments at 23; NYISO Reply Comments at 4-5; PG&E Reply Comments at 2-3.

shortage of qualified engineers, delayed data from interconnection customers, affected system coordination, cascading restudies caused by withdrawals, and the increasing complexity of studies due to new types of generating facilities.[1672] Some commenters contend that the record supports retaining the reasonable efforts standard because third-party forces are common to most study delays.[1673]

885. Some commenters argue that data from reports required by Order No. 845 does not support the NOPR proposal.[1674] AEP notes that the data referenced in the NOPR represents only one year and does not support the conclusion that transmission providers are intentionally slow in interconnection queue processing.[1675] MISO notes that its Order No. 845 reports show that the majority of delays are caused by the need to wait for

[1672] AEP Initial Comments at 25-26; Ameren Initial Comments at 20; Avangrid Initial Comments at 9-10, 29; Dominion Reply Comments at 19; Indicated PJM TOs Reply Comments at 22-24; ISO-NE Initial Comments at 35-36; ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 73-74; MISO TOs Initial Comments at 15-16, 23-24; National Grid Initial Comments at 30; NESCOE Reply Comments at 11-12; NRECA Initial Comments at 9, 33-34; NYISO Initial Comments at 26-27; OMS Initial Comments at 15; Pacific Northwest Utilities Initial Comments at 9-10; PacifiCorp Initial Comments at 32-35; PG&E Initial Comments at 7; PG&E Reply Comments at 3-4; Puget Sound Initial Comments at 9; SDG&E Reply Comments at 1; Southern Initial Comments at 5, 30; State Agencies Initial Comments at 12-14; Tri-State Initial Comments at 17-18; U.S. Chamber of Commerce Initial Comments at 10; WIRES Initial Comments at 9; Xcel Initial Comments at 38.

[1673] Eversource Initial Comments at 28; MISO TOs Reply Comments at 13; PacifiCorp Initial Comments at 33; Southern Initial Comments at 30; U.S. Chamber of Commerce Initial Comments at 10.

[1674] AEP Initial Comments at 25; MISO Initial Comments at 72.

[1675] AEP Initial Comments at 25-27.

affected systems studies.[1676] NYISO states that its August 2022 Order No. 845 report, and other recent RTO/ISO reports, detail the various drivers of delays, which are typically outside their control.[1677] NYISO argues that it would not be reasoned decision-making for the Commission to ignore these reports and draw an overly simplistic conclusion that the reasonable efforts standard is to blame for study delays. PG&E and Southern note that their Order No. 845 data indicates that they have no delayed studies.[1678]

886. Conversely, AEE and Public Interest Organizations respond that commenters that claim that study delays are caused by factors beyond transmission providers' control fail to acknowledge the availability of potential solutions, such as increasing expenditures to attract and retain staff and policy and process improvements.[1679] ACE-NY asserts that, while other parties can cause delays, transmission providers are also responsible for delays.[1680] SEIA argues that interconnection request withdrawals are often similarly outside interconnection customers' control.[1681] AEE contends that accepting high

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[1676] MISO Initial Comments at 14, 72.

[1677] NYISO Initial Comments at 27-29.

[1678] PG&E Initial Comments at 4-6; Southern Initial Comments at 30-31.

[1679] AEE Reply Comments at 34-35; MISO TOs Initial Comments at 18; Public Interest Organizations Reply Comments at 2-4.

[1680] ACE-NY Reply Comments at 3.

[1681] SEIA Reply Comments at 16.

interconnection queue volumes as a legitimate cause for delays would amount to providing a permanent free pass to transmission providers to exceed study deadlines.[1682]

887. Several commenters who oppose the NOPR proposal assert that transmission providers engage in good faith efforts to process the interconnection queue in a timely manner[1683] and that there is no evidence to the contrary.[1684] Commenters argue that transmission providers already have sufficient motivation to process the interconnection queue in a timely manner because: (1) their own interconnection requests are processed in the exact same manner as third parties; (2) they need to ensure an adequate amount of generation to meet load and reserve margin requirements; and (3) they have to file reports with the Commission and can face complaints or enforcement action for poor performance.[1685] Commenters assert that penalties will be ineffective in speeding

[1682] AEE Reply Comments at 27.

[1683] AEP Initial Comments at 26; Avangrid Initial Comments at 29; Dominion Initial Comments at 34; EEI Initial Comments at 15; Eversource Initial Comments at 21-22; Indicated PJM TOs Initial Comments at 5-6, 38; MISO TOs Initial Comments at 15-17; NextEra Initial Comments at 29; NYISO Initial Comments at 26-27; OMS Initial Comments at 15; Puget Sound Initial Comments at 9-10; State Agencies Initial Comments at 12; Vermont Electric and Vermont Transco Initial Comments at 2.

[1684] AEP Initial Comments at 26; Avangrid Initial Comments at 29; Dominion Initial Comments at 34; EEI Initial Comments at 15; Eversource Initial Comments at 21-22; Indicated PJM TOs Initial Comments at 5-6, 38; MISO TOs Initial Comments at 15-17; NextEra Initial Comments at 29; NYISO Initial Comments at 26-27; Puget Sound Initial Comments at 9-10; State Agencies Initial Comments at 12.

[1685] AEP Initial Comments at 26; Dominion Initial Comments at 36; Indicated PJM TOs Initial Comments at 37-38; MISO TOs Initial Comments at 16; PJM Initial Comments at 56; Puget Sound Initial Comments at 10.

interconnection queue processing time because the main causes of study delays will remain.[1686] MISO TOs contend that the Commission proposes to compound the problem of study delays by requiring transmission owners and providers to manage delays that are out of their control, while simultaneously proposing to require transmission providers to offer additional studies.[1687]

888. NextEra argues that penalties will be counterproductive if not paired with constructive guidance to transmission providers on how to perform interconnection studies in a timelier manner because penalties could either divert resources away from interconnection studies and lead to conflict about allocating penalties in RTOs/ISOs or be accepted as a cost of doing business.[1688]

889. Indicated PJM TOs contest the NOPR's citation to testimony provided by Utah Public Service Commission Chairman Thad LeVar, noting that Chairman LeVar also acknowledged that best practices vary between RTO/ISO and non-RTO/ISO regions and that penalties do not always result in the best consequences.[1689]

[1686] Ameren Initial Comments at 20; Bonneville Initial Comments at 15; Dominion Initial Comments at 34-35; Eversource Initial Comments at 20-21; Indicated PJM TOs Initial Comments at 39-40; MISO Initial Comments at 13, 71; NextEra Initial Comments at 30; NextEra Reply Comments at 11; North Dakota Commission Initial Comments at 5; PacifiCorp Initial Comments at 34; PG&E Reply Comments at 3; PJM Initial Comments at 7-8, 56; R Street Initial Comments at 14; Southern Initial Comments at 30; State Agencies Initial Comments at 12.

[1687] MISO TOs Reply Comments at 12.

[1688] NextEra Initial Comments at 29-30.

[1689] Indicated PJM TOs Initial Comments at 38 (citing May Joint Task Force Tr.

890. Some commenters argue that the NOPR proposal is an unsupported shift from recent precedent.[1690] Commenters note that the Commission expressly declined to impose penalties for study delays in Order No. 845 and argue that there is no change in circumstance or concrete evidence to justify reversal of that prior finding.[1691]

891. Commenters also note that, although the Commission based its penalty proposal on Order No. 890, there are significant differences.[1692] First, commenters explain that the Order No. 890 penalties only apply when a transmission provider fails to meet multiple study deadlines, whereas the NOPR proposes to impose penalties each time a study deadline is missed.[1693] Second, commenters point out that the Order No. 890 penalty structure protects due process through an opportunity to present evidence that delays were outside the transmission provider's control or due to extenuating circumstances, whereas the NOPR proposal does not.[1694] Third, PacifiCorp explains that interconnection studies are more complex, numerous, and susceptible to delays than the transmission

46:11-13, 89:17-18 (Thad LeVar)).

[1690] EEI Initial Comments at 14; MISO Reply Comments at 21.

[1691] MISO TOs Initial Comments at 21-22; NYISO Initial Comments at 26; PG&E Initial Comments at 6; PG&E Reply Comments at 3.

[1692] MISO TOs Initial Comments at 19; PacifiCorp Initial Comments at 33-34.

[1693] MISO TOs Initial Comments at 19; MISO Reply Comments at 21; Tri-State Initial Comments at 18.

[1694] Eversource Initial Comments at 30; MISO Reply Comments at 21; MISO TOs Initial Comments at 19-21.

service studies at issue in Order No. 890.[1695] Affected Interconnection Customers argue that the Commission's comparison to Order No. 890's penalty structure for transmission service requests is misplaced because the size and scale of the current interconnection queue backlog is significantly different than transmission queues when Order No. 890 was issued.[1696] Similarly, Invenergy notes that the reference to transmission service requests is inapplicable because the interconnection process uses a cluster study.[1697]

892. EEI and Eversource state that the NOPR proposal represents a departure from the good utility practice standard, which the Commission uses in many other contexts and is part of the definition of reasonable efforts.[1698] EEI and Eversource assert that the Commission has not adequately explained why reliance on good utility practice remains sufficient in other situations, but not for interconnection studies.

893. Commenters contend that firm study deadlines are not reasonable or feasible because interconnection studies are complex and each study is different in scope, size, and needed coordination.[1699] Some commenters also note that the current deadlines were

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[1695] PacifiCorp Initial Comments at 33-34.

[1696] Affected Interconnection Customers Initial Comments at 25.

[1697] Invenergy Initial Comments at 30.

[1698] EEI Initial Comments at 15; Eversource Initial Comments at 22-24.

[1699] AECI Initial Comments at 6; Avangrid Initial Comments at 28-29; Bonneville Initial Comments at 15; Clean Energy States Initial Comments at 10-11; Eversource Initial Comments at 27; Idaho Power Initial Comments at 10; ISO-NE Initial Comments at 35-36; ISO/RTO Council Reply Comments at 2; MISO TOs Initial Comments at 15; National Grid Initial Comments at 30; PJM Initial Comments at 58; Puget Sound Initial Comments at 10; SPP Initial Comments at 13; U.S. Chamber of Commerce Initial

established almost 20 years ago, when the transmission providers had significantly fewer interconnection requests to study.[1700] SPP contends that cluster studies are more prone to study delays given the interdependencies between interconnection requests and number of parties that need to cooperate.[1701] Commenters also assert that the other NOPR proposals, including the optional resource solicitation study, informational studies, and evaluation of advanced transmission technologies, add significant burdens to the study process that will make it even more challenging to comply with strict deadlines.[1702]

894. Some commenters express concern that the penalties could reduce coordination between transmission providers, interconnection customers, and affected systems.[1703] Commenters note that the enforcement of deadlines could be expensive, involve contentious disputes, and disrupt ongoing studies.[1704] Commenters state that transmission

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Comments at 10; WIRES Initial Comments at 10.

[1700] Eversource Initial Comments at 27; Indicated PJM TOs Initial Comments at 37-38.

[1701] SPP Initial Comments at 11-12.

[1702] *Id.* at 13; Indicated PJM TOs Initial Comments at 36; MISO Reply Comments at 7; PPL Initial Comments at 24.

[1703] Alliant Energy Initial Comments at 6; EEI Initial Comments at 15; Eversource Initial Comments at 25-26; MISO Reply Comments at 21; North Dakota Commission Initial Comments at 6.

[1704] Clean Energy Associations Initial Comments at 45; EEI Initial Comments at 15; MISO Initial Comments at 13, 71; MISO TOs Initial Comments at 24; MISO TOs Reply Comments at 10; National Grid Initial Comments at 30; NextEra Initial Comments at 30; OMS Initial Comments at 15; PacifiCorp Initial Comments at 35; R Street Initial Comments at 14; SPP Initial Comments at 14.

providers will also likely provide less flexibility to interconnection customers to remedy deficiencies or modify interconnection requests.[1705] MISO TOs assert that this could threaten reliability.[1706] NESCOE points out that firm penalties may impede the interconnection of emerging technologies by limiting flexibility to work on modeling and data requirements.[1707]

895. PJM argues that using penalties to offset study costs for interconnection customers introduces perverse incentives for the interconnection customer to dispute and thereby delay its study reports to receive the penalty money.[1708] In response, however, AEE notes that interconnection customers bear greater costs due to delays, which creates an incentive to move forward as quickly as possible.[1709]

896. Commenters note that the same engineers that conduct interconnection studies also have other responsibilities such as transmission planning[1710] and responding to extreme weather events.[1711] Ameren states that penalties could motivate transmission providers to

[1705] Dominion Reply Comments at 21; EEI Initial Comments at 15; Eversource Initial Comments at 25-26; NYISO Initial Comments at 38-39; WIRES Initial Comments at 10.

[1706] MISO TOs Reply Comments at 18-19.

[1707] *Id.*; NESCOE Initial Comments at 17.

[1708] PJM Initial Comments at 57.

[1709] AEE Reply Comments at 35-36.

[1710] Indicated PJM TOs Initial Comments at 6.

[1711] National Grid Initial Comments at 30.

redirect resources towards interconnection studies to the detriment of other necessary functions.[1712] Some commenters argue that penalties will deprive transmission providers of financial resources or harm work environments and employee morale, making it more difficult to recruit and retain personnel qualified to perform the studies.[1713]

897. A number of commenters express concern that the NOPR proposal may result in less accurate studies because transmission providers may prioritize meeting deadlines over accuracy and identification of the most efficient solutions.[1714] Some commenters further assert that penalties may impair system reliability because the study timelines are too short to carry out sufficient analysis.[1715] Some commenters argue that the penalties

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[1712] Ameren Initial Comments at 21.

[1713] Eversource Initial Comments at 25-26; Indicated PJM TOs Initial Comments at 24, 40; MISO TOs Initial Comments at 24; Pacific Northwest Utilities Initial Comments at 12; PJM Initial Comments at 57.

[1714] AECI Initial Comments at 6; Alliant Energy Initial Comments at 6; Avangrid Initial Comments at 9-10, 30; Bonneville Initial Comments at 15-16; CESA Reply Comments at 8; Clean Energy Buyers Initial Comments at 10-11; Enel Initial Comments at 48; Indicated PJM TOs Reply Comments at 26; ISO/RTO Council Initial Comments at 8; Longroad Energy Reply Comments at 14; MISO Initial Comments at 13, 71, 77-78; MISO TOs Initial Comments at 14, 24; National Grid Initial Comments at 30; NESCOE Reply Comments at 13; NextEra Reply Comments at 11; North Dakota Commission Initial Comments at 6; NRECA Initial Comments at 34; NYISO Initial Comments at 38-39; NYTOs Initial Comments at 24-28; Omaha Public Power Initial Comments at 12; OMS Initial Comments at 15; Ørsted Initial Comments at 15; PacifiCorp Reply Comments at 6; PJM Initial Comments at 8, 56-57; PPL Initial Comments at 19; SPP Initial Comments at 11-12; Tri-State Initial Comments at 18; Xcel Initial Comments at 38.

[1715] AEP Initial Comments at 28; Dominion Reply Comments at 21; NYISO Initial Comments at 39; PJM Initial Comments at 8, 56-57.

could force transmission providers to complete studies without necessary data, which could also lead to inaccurate results and cause restudy.[1716] Some commenters state that less accurate studies would harm interconnection customers because interconnection customers cannot rely on them to make sound business decisions.[1717] Avangrid states that transmission providers could use more conservative assumptions and "stock solutions" to streamline studies, which could increase interconnection costs.[1718] However, in response to these comments, AEE states that the implementation of timelines and penalties does not inherently determine the evaluation process for clusters.[1719] AEE notes that inaccurate study results occur today without firm deadlines and that accuracy can be improved even with deadlines.[1720] New Jersey Commission disagrees that there is an inherent tradeoff between system reliability and holding transmission providers accountable, arguing that failing to bring sufficient new generating facilities online can create considerable reliability and economic risks.[1721]

[1716] Ameren Initial Comments at 21; MISO Initial Comments at 78; SPP Initial Comments at 12-13.

[1717] Enel Initial Comments at 48-49; MISO Initial Comments at 78; OMS Initial Comments at 15; SPP Initial Comments at 12.

[1718] Avangrid Initial Comments at 30.

[1719] AEE Reply Comments at 33.

[1720] *Id.* at 31-32.

[1721] New Jersey Commission Reply Comments at 3.

898. Commenters express concern that the cost of penalties and compliance mechanisms may be passed down to customers and increase transmission costs.[1722] Clean Energy Buyers argue that the penalties, if they flow through to interconnection customers, could outweigh the benefits gained from other reforms and lead to disputes over the allocation of penalty amounts.[1723] R Street points out that the Commission will have to ensure that transmission providers cannot translate penalties into cost recovery at either the federal or retail level.[1724]

899. Some commenters characterize the NOPR proposal as a strict liability approach to penalties and argue that it is unjust and unreasonable, arbitrary and capricious, and a violation of due process rights and the Administrative Procedures Act to impose penalties without a fact-based finding of fault.[1725] Some commenters emphasize that the NOPR proposal provides no possibility for the transmission provider to explain the circumstances for the delay, even though the delay is often outside of the transmission

[1722] Alliant Energy Initial Comments at 6-7; NARUC Initial Comments at 19; NYISO Reply Comments at 6-7, 9; R Street Initial Comments at 14; SEIA Reply Comments at 17; State Agencies Initial Comments at 12; Tri-State Initial Comments at 18; Vermont Electric and Vermont Transco Initial Comments at 2.

[1723] Clean Energy Buyers Initial Comments at 10.

[1724] R Street Initial Comments at 15; *see also* SEIA Reply Comments at 17.

[1725] MISO Initial Comments at 13, 71; MISO Reply Comments at 19-20; MISO TOs Initial Comments at 18; SPP Initial Comments at 14; NYISO Initial Comments at 40 (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Enforcement of Statutes, Reguls. & Orders*, 123 FERC ¶ 61,156, at PP 50-71 (2008)); WIRES Initial Comments at 10.

provider's control.[1726] Dominion argues that there are three practical concerns with the NOPR proposal: (1) how disputes about who is at fault will be resolved; (2) who decides fault; and (3) whether the interconnection study should be delayed while the dispute is resolved.[1727]

900. Some commenters argue that the reasonable efforts standard is the right approach considering the complex dynamics of the interconnection study process and constantly changing circumstances.[1728] EEI asserts that the reasonable efforts standard is the best approach to govern the interconnection process, which is flexible to allow for the optimum exercise of engineering judgement while ensuring accountability for egregious delays or what is not consistent with good utility practice.[1729] MISO TOs note that, in Order No. 2003, the Commission explained that the reasonable efforts standard was a high standard because parties use it when protecting their own interests and applying this standard to all parties would "ensure comparable treatment."[1730]

[1726] ISO-NE Initial Comments at 35; ISO/RTO Council Initial Comments at 2; MISO Initial Comments at 7.

[1727] Dominion Reply Comments at 24.

[1728] Avangrid Initial Comments at 10, 30-31; Bonneville Initial Comments at 16; Indicated PJM TOs Initial Comments at 36; NYISO Initial Comments at 30-31; PG&E Reply Comments at 3-4; WIRES Initial Comments at 10.

[1729] EEI Reply Comments at 16.

[1730] MISO TOs Reply Comments at 6-7 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 69).

901. NYISO contends that the reasonable efforts standard and Order No. 845 reporting requirements provide the Commission and stakeholders with information to evaluate the length of time taken by RTOs/ISOs to finish studies, compare their performance, and identify and investigate when a particular entity is systematically delaying studies, which will allow the Commission and stakeholders to take appropriate action.[1731] SPP proposes that the Commission retain the reasonable efforts standard and make improvements to it or enforce it more strictly.[1732]

902. WAPA notes that, as a federal power marketing administration, it has statutory duties that take precedence over deliverables established by the Commission and cannot be subject to monetary penalties without a waiver of sovereign immunity.[1733] Avangrid notes that many transmission providers and transmission owners do not earn rates of return for interconnection facilities or network upgrades and do not profit from interconnection studies, so penalties would reduce shareholder return on equity.[1734]

iii. <u>Comments on Specific Proposal</u>

903. Some commenters support eliminating the reasonable efforts standard but do not support the proposed financial penalties.[1735] CAISO argues that the Commission should

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[1731] NYISO Initial Comments at 31.

[1732] SPP Initial Comments at 15.

[1733] WAPA Initial Comments at 10.

[1734] Avangrid Initial Comments at 30.

[1735] CAISO Initial Comments at 25-26; Clean Energy Buyers Initial Comment at

simply prohibit late studies and mandate firm study deadlines because the proposed penalties will enable transmission providers to continue completing studies late if they are willing to pay the price.[1736] CAISO explains that, if a transmission provider cannot meet its study deadlines, it should be required to amend its tariff.[1737] Other commenters, as described below, have various comments on the specific penalty proposal.

(a) Penalty Amount

904. Some commenters advocate for larger penalties than the NOPR proposal.[1738] Some commenters contend that the proposed penalty amount is *de minimis*[1739] or that a $500 per business day penalty is likely too small to prompt a change in behavior.[1740] Cypress Creek argues that penalties should be commensurate with the magnitude of liquidated damages that interconnection customers face if they do not meet their

9-10; MISO Initial Comments at 13, 71, 79; Shell Initial Comments at 10.

[1736] CAISO Initial Comments at 25-26; PG&E Reply Comments at 4.

[1737] CAISO Initial Comments at 25-26.

[1738] ACE-NY Initial Comments at 12; Affected Interconnection Customers Initial Comments at 25-26; CESA Initial Comments at 11; CESA Reply Comments at 9; Consumers Energy Initial Comments at 6; CREA and NewSun Reply Comments at 56; Cypress Creek Initial Comments at 24; EPSA Initial Comments at 11; Fervo Energy Initial Comments at 6; Invenergy Initial Comments at 29; Pine Gate Initial Comments at 39.

[1739] CESA Reply Comments at 8; Invenergy Initial Comments at 29; NARUC Initial Comments at 14.

[1740] ACE-NY Initial Comments at 12; Affected Interconnection Customers Initial Comments at 24-26; CESA Initial Comments at 11; Clean Energy Associations Initial Comments at 44; Consumers Energy Initial Comments at 6; ELCON Initial Comments at 7-8; Pine Gate Initial Comments at 39.

contractual deadlines.[1741] ACE-NY proposes a penalty of $5,000 to $25,000 per day, depending on cluster size, if the Commission chooses a per-cluster-per-day penalty structure.[1742] Affected Interconnection Customers propose that the Commission adopt a penalty of $2,500 per day capped at $2 million.[1743] Public Interest Organizations state that there is not sufficient consensus in the record to move forward with the $500 per day penalty amount and suggest that the Commission hold a technical conference to determine the final amount.[1744]

905. Some commenters argue that the penalties should increase through the study process because later-stage study delays have greater impacts on interconnection customers, which are required to make increasing commitments throughout the study process.[1745] Invenergy recommends penalty amounts of $5,000 per day for cluster studies, $6,000 per day for cluster restudies, and $7,000 per day for facilities studies.[1746]

906. Pine Gate expresses concern that the proposed penalty amounts do not correspond to the costs imposed on interconnection customers as a result of the late study results,

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[1741] Cypress Creek Initial Comments at 24.

[1742] ACE-NY Initial Comments at 12.

[1743] Affected Interconnection Customers Initial Comments at 5, 26; CESA Reply Comments at 9.

[1744] Public Interest Organizations Reply Comments at 5-6.

[1745] CESA Initial Comments at 11; Clean Energy Associations Initial Comments at 44; CREA and NewSun Reply Comments at 57; Invenergy Initial Comments at 30.

[1746] Invenergy Initial Comments at 30.

explaining that the penalty amount is dwarfed by the overall cluster study cost and that the low daily rate would require an interconnection study to be delayed years before the amounts would approach the study deposit amounts.[1747] As an example, Pine Gate refers to the most recent MISO interconnection queue submissions: MISO received 956 interconnection requests, totaling 170.8 GW of new generation, and collected $687,980,000 in study deposits. Pine Gate notes that, under a late study fee of $500 per day, a study would have to be delayed 1,375,960 days—or 3,770 years—before equaling the cost of study deposits. Further, Pine Gate explains that the daily carrying cost on the study deposit cost at the prevailing development loan interest rate of 10% is approximately $188,487.67. Thus, Pine Gate states that, before the proposed 10-day grace period has elapsed, interconnection customers will have spent $1,884,876 in additional interest costs.

907. In response to requests for higher penalties, some commenters argue that there is no legal or policy justification for making the proposed penalty scheme harsher and more inequitable.[1748] MISO argues that NERC reliability penalties are typically assessed at under $500 per day, if at all, and NERC non-critical infrastructure protection penalties are also assessed at far lower values. MISO contends that, because these “moderate risk”

[1747] Pine Gate Initial Comments at 39-40.

[1748] MISO TOs Reply Comments at 19; NYISO Reply Comments at 1.

violations merit such low penalties, there is no support for $500 per day penalties for delayed interconnection studies.[1749]

908. NARUC supports the proposal to cap the penalty amount at 100% of the total study deposit received.[1750] Several commenters argue that the penalty amount should be capped at an amount greater than 100% of the total study deposit received.[1751] Invenergy requests that the Commission clarify that the cap is not reduced by any withdrawal penalties.[1752] Public Interest Organizations propose that transmission providers that reach the cap issue a compliance statement explaining in detail the source of the delay and use penalty amounts above the cap to hire third-party consultants to conduct interconnection studies.[1753]

909. Several commenters argue that the penalty amount should not be capped.[1754] Some commenters note that financial penalties for interconnection customers are not

[1749] MISO Reply Comments at 23.

[1750] NARUC Initial Comments at 15.

[1751] Interwest Initial Comments at 8; Invenergy Initial Comments at 31; Northwest and Intermountain Initial Comments at 14.

[1752] Invenergy Initial Comments at 31.

[1753] Public Interest Organizations Initial Comments at 36.

[1754] *Id.* at 35-36; ACE-NY Initial Comments at 13; AEE Reply Comments at 37; Consumers Energy Initial Comments at 6; CREA and NewSun Initial Comments at 84; Cypress Creek Initial Comments at 23-24; SEIA Initial Comments at 34.

capped at their study deposits.[1755] Other commenters argue that the study deposit amount cap is not commensurate with the harm late studies cause interconnection customers.[1756]

(b) Penalty Structure

910. Some commenters suggest a per-customer per-day penalty structure, rather than the NOPR proposal for a per-cluster per-day structure.[1757] AEE suggests that the Commission assess penalties based on the higher value of $500 per day or $100 per customer per day.[1758] Multiple commenters oppose a penalty structure based on the number of interconnection customers because transmission providers have no control over the number of interconnection requests they receive and higher request volumes lead to more complex studies with more potential for delay.[1759]

911. Some commenters suggest a penalty structure based on the cluster's characteristics.[1760] Public Interest Organizations suggest a penalty structure set as a

[1755] AEE Initial Comments at 31; Northwest and Intermountain Initial Comments at 15.

[1756] CREA and NewSun Initial Comments at 84; SEIA Initial Comments at 34.

[1757] ACE-NY Initial Comments at 13; SEIA Initial Comments at 34. PG&E seeks clarification on whether the penalties will apply per-customer per-day or per-cluster per-day. PG&E Initial Comments at 8.

[1758] AEE Initial Comments at 31.

[1759] CAISO Initial Comments at 27; MISO Reply Comments at 24; Xcel Initial Comments at 38.

[1760] Google Initial Comments at 17; NARUC Initial Comments at 20-21; Public Interest Organizations Initial Comments at 34.

percentage of the total study deposit received per day.[1761] Google recommends the penalty structure take into account both the size of the interconnection request and the magnitude of a study delay's impact on other interconnection requests in the interconnection queue, which would focus penalties on delays that have the most impact on overall processing of the interconnection queue.[1762] NARUC explains that the penalty should not be targeted at the number of interconnection customers in a cluster that are delayed but at the desirable characteristics of the generating facilities being delayed.[1763]

912. Some commenters suggest that the Commission require transmission providers to discount study costs for delayed studies by the percentage of time they are delayed in completing such study, subject to a maximum discount set by the Commission.[1764] Clean Energy States propose that, if an interconnection study is late, the transmission provider could not charge the interconnection customers for the cost of the study, providing the interconnection customer a modest amount of compensation for the delay.[1765] PacifiCorp argues that neither the host transmission provider nor affected system operator should be

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[1761] Public Interest Organizations Initial Comments at 34.

[1762] Google Initial Comments at 17.

[1763] NARUC Initial Comments at 20-21.

[1764] AEE Initial Comments at 28-29; AEE Reply Comments at 36-37; Clean Energy Associations Initial Comments at 45 (explaining that, under their preferred approach, if a study took 30 calendar days past a 150-calendar day deadline, that would result in a 20% discount on study costs); Longroad Energy Reply Comments at 14; Pine Gate Initial Comments at 40; SEIA Reply Comments at 17.

[1765] Clean Energy States Initial Comments at 10-11.

penalized if either party delays the work of the other, especially if the delays are caused by transmission providers that are not public utilities.[1766]

913. NRECA and Tri-State assert that the final rule should allow transmission providers to stop or reset the clock in the event of interconnection customer-initiated delays.[1767] Similarly, APPA-LPPC state that the clock should not start running on study deadlines until after the interconnection customer submits all necessary information, including curing any deficiencies.[1768] Tri-State asserts that a delay should not be penalized if it is caused by a higher-queued cluster going through a restudy.[1769] Tri-State also suggests that, if the Commission moves forward with penalties for late studies, additional language should be added requiring interconnection customers to provide needed information within a specified time frame in order to complete the studies. R Street claims that transmission providers can game requirements that trigger penalties, such as by forcing requesting parties to resubmit specifications to restart the processing clock.[1770]

[1766] PacifiCorp Initial Comments at 37.

[1767] NRECA Initial Comments at 34; Tri-State Initial Comments at 19.

[1768] APPA-LPPC Initial Comments at 21.

[1769] Tri-State Initial Comments at 18.

[1770] R Street Initial Comments at 15.

(c) <u>Penalty Allocation and Distribution</u>

914. Many commenters agree that transmission providers, including RTOs/ISOs, must not pass on penalty costs to ratepayers.[1771] Public Interest Organizations support enabling transmission providers to allocate penalty costs to responsible parties but recommend maintaining presumption of fault with the transmission providers themselves and disallowing transmission providers from recovering penalty amounts.[1772]

915. Several commenters support distributing the penalties collected from transmission providers to the impacted interconnection customers.[1773] PG&E seeks clarification on how the penalty would be distributed (i.e., equal distribution to each interconnection customers, equal distribution among interconnection requests, or distributed based on project size).[1774] Fervo Energy supports the proposal to require transmission providers to

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[1771] Clean Energy Associations Initial Comments at 44; Consumers Energy Initial Comments at 6; Cypress Creek Initial Comments at 24; Google Initial Comments at 18; Illinois Commission Initial Comments at 9; NARUC Initial Comments at 15; New Jersey Commission Initial Comments at 13-14; OPSI Initial Comments at 8-9; SEIA Initial Comments at 34; *see also* Ohio Commission Consumer Advocate Initial Comments at 13 ("Although FERC states that the proposed penalties would not be recoverable in transmission rates, we believe such imposition will inevitably impact ratepayers, and not rightfully so, unless it can be clearly demonstrated that the proposed $500/day penalty is not passed along[.]"). *But see* Iowa Commission Initial Comments at 5-6 ("[I]t is not correct to assume that the penalties would result in ultimate costs to the customers/ratepayers as some of the stakeholders contend[.]").

[1772] Public Interest Organizations Reply Comments at 6, 8-9.

[1773] ACE-NY Initial Comments at 12; Interwest Initial Comments at 9; NARUC Initial Comments at 14-15; Northwest and Intermountain Initial Comments at 15.

[1774] PG&E Initial Comments at 8.

provide quarterly public reports on total amounts of penalties and the highest penalty for a single interconnection request.[1775] Google argues that transmission providers should make such a report available annually to state commissions to ensure penalties are not paid by consumers.[1776]

916. National Grid argues that the Commission should allow transmission providers to recover penalties from an interconnection customer if the customer is responsible for the delay.[1777]

(d) <u>Penalty Recovery in RTOs/ISOs</u>

917. Some commenters support the proposal to allow RTOs/ISOs to recover the cost of specific interconnection study penalties from transmission owners responsible for study delays through FPA section 205 filings.[1778] ACORE recommends that RTOs/ISOs provide explicit criteria for how they will determine which parties are responsible for or contributed to study delays.[1779] AEE suggests that the Commission assign RTO/ISO penalties to transmission owners by default.[1780] In response to AEE's proposal, MISO

[1775] Fervo Energy Initial Comments at 6.

[1776] Google Initial Comments at 20.

[1777] National Grid Initial Comments at 33.

[1778] ACE-NY Initial Comments at 12; CESA Reply Comments at 8-9; Google Initial Comments at 19; NARUC Initial Comments at 17; Public Interest Organizations Initial Comments at 35; SEIA Initial Comments at 34.

[1779] ACORE Initial Comments at 8.

[1780] AEE Initial Comments at 30.

TOs assert that imposing penalties on transmission owners that did not have control over the causes of study delays does not follow cost causation principles.[1781]

918. Some commenters express concerns about how RTOs/ISOs will pay penalties if no member is found responsible.[1782] OPSI contends that, because RTOs/ISOs rely on transmission owners to process interconnection queues, they may be reluctant to seek penalty recovery from them.[1783]

919. Several commenters oppose the proposal to allow RTOs/ISOs to recover the cost of specific interconnection study penalties from transmission owners responsible for study delays through FPA section 205 filings.[1784] Such commenters assert that the proposal does not provide sufficient detail on how penalties will work in RTO/ISO regions.[1785] Some commenters contend that imposing penalties on RTOs/ISOs will not expedite interconnection studies because the penalties will not address the actual source of study delays and will disrupt processing of interconnection queues.[1786] ISO-NE and

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[1781] MISO TOs Reply Comments at 20-21 (citing *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

[1782] Alliant Energy Initial Comments at 6-7; APPA-LPPC Initial Comments at 22; NARUC Initial Comments at 18; NESCOE Initial Comments at 16.

[1783] OPSI Initial Comments at 9.

[1784] AEP Initial Comments at 27-28; CAISO Initial Comments at 26; Dominion Initial Comments at 35-36; EEI Initial Comments at 17; ISO-NE Initial Comments at 34-36; SPP Initial Comments at 15; TAPS Initial Comments at 3.

[1785] Eversource Initial Comments at 29; PJM Initial Comments at 57.

[1786] ISO/RTO Council Initial Comments at 2; WIRES Initial Comments at 11.

MISO note that delays may not be the fault of the RTO/ISO because transmission owners often conduct the studies.[1787]

920. Commenters argue that the proposed penalty system would impose administrative and litigative burden on RTOs/ISOs and the Commission.[1788] Indicated PJM TOs argue that the process before the Commission will need to be a complete *de novo* review.[1789] SoCal Edison and New York State Department note that the penalty system would likely require additional resources to track and allocate penalties, which could increase the cost of administering interconnection queues.[1790] The ISO/RTO Council claims that, under the NOPR proposal, RTOs/ISOs will need to act as fact-finding tribunals to fairly assign penalties before making an FPA section 205 filing, which would be a time- and resource-consuming process at odds with the goal of reducing interconnection study delays.[1791]

[1787] ISO-NE Initial Comments at 35; MISO Initial Comments at 14, 73-74.

[1788] Avangrid Reply Comments at 8; CAISO Initial Comments at 26; Indicated PJM TOs Reply Comments at 27; ISO-NE Initial Comments at 35; ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 16, 77; MISO TOs Reply Comments at 21-22; New York State Department Initial Comments at 10-11; NYISO Initial Comments at 33; PJM Initial Comments at 57-58; SoCal Edison Initial Comments at 19.

[1789] Indicated PJM TOs Initial Comments at 44.

[1790] New York State Department Initial Comments at 10-11; SoCal Edison Initial Comments at 19.

[1791] ISO/RTO Council Initial Comments at 5; *see also* Indicated PJM TOs Initial Comments at 37 (explaining that it would be difficult for RTOs to determine who is at fault for study delays).

TAPS avers that RTOs/ISOs would need precise and well-supported cases to successfully assign penalties to responsible transmission owners.[1792]

921. Commenters contend that having RTOs/ISOs assign penalties to responsible entities would harm coordination or create tension between RTOs/ISOs, transmission owners, interconnection customers, and other parties.[1793] AEP and TAPS assert that the proposal could discourage RTO/ISO participation.[1794]

922. Commenters express concern around imposing penalties on non-profit RTOs/ISOs, which have no ability to pay fines without collecting them from another party.[1795] MISO contends that, for RTOs/ISOs, penalties without specified payees are effectively a tax on LSEs.[1796]

923. NYISO contends that penalties would threaten RTOs'/ISOs' financial viability.[1797] NYISO explains that RTO/ISO penalties and challenges to penalty recovery have been rare. NYISO claims that there are no examples of Commission denials of penalty cost recovery, so RTOs/ISOs would be subject to considerable uncertainty about their ability

[1792] TAPS Initial Comments at 6-7.

[1793] AEP Initial Comments at 27; Dominion Initial Comments at 35-36; Indicated PJM TOs Reply Comments at 6-7, 27; NextEra Initial Comments at 30; NYISO Initial Comments at 39-40; PJM Initial Comments at 57-58.

[1794] AEP Initial Comments at 27-28; TAPS Initial Comments at 6.

[1795] MISO Initial Comments at 13, 71; MISO TOs Reply Comments at 20; NYISO Reply Comments at 10.

[1796] MISO Initial Comments at 13, 72.

[1797] NYISO Initial Comments at 32.

to recover study penalties.[1798] NYISO argues that, if the Commission is likely to accept RTO/ISO penalty recovery proposals, then the penalties would serve no purpose because they would be passed to customers and fail to incentivize RTOs/ISOs to complete studies in a more timely manner.

924. NYISO argues that it is unjust and unreasonable and unduly discriminatory to apply the same level of penalties to RTOs/ISOs as other transmission providers because they are differently situated than other transmission providers.[1799] NYISO states that an identical penalty would be much more punitive on RTOs/ISOs than other transmission providers, so any financial penalties imposed on RTOs/ISOs should be smaller in size and slower to trigger. NYISO requests that, if the Commission requires penalties, it allow RTOs/ISOs to propose in their compliance filings appropriate rules for their own regions.

925. NYISO further argues that Order Nos. 672[1800] and 890 do not support subjecting RTOs/ISOs to the same penalties as non-independent transmission providers.[1801] NYISO argues that the proposed penalties pose a greater risk to RTOs/ISOs than reliability penalties, which have been assessed in rare circumstances and are subject to the

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[1798] *Id.* at 37.

[1799] *Id.* at 41.

[1800] *Rules Concerning Certification of the Elec. Reliability Org.; & Procs. for the Establishment, Approval, & Enf't of Elec. Reliability Standards*, Order No. 672-A, 71 FR 19814 (Apr. 18, 2006), 114 FERC ¶ 61,104 (2006).

[1801] NYISO Initial Comments at 32-33.

Commission's close scrutiny.[1802] NYISO also notes that it does not conduct the kinds of transmission studies addressed in Order No. 890, so the formal applicability of the Order No. 890 penalty regime to RTOs/ISOs does not mean that application of penalties to RTOs/ISOs is practicable.[1803]

926. Many commenters express concerns that RTOs/ISOs may pass penalty costs through to transmission owners or ratepayers who did not contribute to study delays, which they claim is unjust and unreasonable.[1804] New York State Department does not support penalties unless they can be recovered from RTO/ISO bonuses or shareholder profits.[1805]

927. Some commenters also argue that the proposal to allow RTOs/ISOs to recover penalties from transmission owners ignores that other entities may be responsible for study delays.[1806] MISO explains, for example, that it has no mechanism to recover penalties from affected systems and that, even for entities subject to MISO's tariff,

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[1802] *Id.* at 33-34.

[1803] *Id.* at 36.

[1804] *Id.* at 32; Alliant Energy Initial Comments at 6-7; EEI Initial Comments 17; Indicated PJM TOs Initial Comments at 37; ISO/RTO Council Initial Comments at 3-4; NARUC Initial Comments at 18; NEPOOL Initial Comments at 16; NESCOE Reply Comments at 11; New York State Department Initial Comments at 10; North Dakota Commission Initial Comments at 6; Omaha Public Power Initial Comments at 11; OMS Initial Comments at 15; R Street Initial Comments at 14; State Agencies Initial Comments at 12-13; TAPS Initial Comments at 3-5; WIRES Initial Comments at 11.

[1805] New York State Department Initial Comments at 10.

[1806] ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 74.

consensus on a penalty pass through mechanism is likely to be elusive.[1807] Several commenters argue that, because RTOs/ISOs will have to pass through the penalty, it will not accomplish the Commission's goals.[1808] NESCOE, however, disagrees that RTOs/ISOs will have to pass through penalty costs but notes that the Commission required RTOs/ISOs to file proposals to recover penalties incurred for reliability standard violations case-by-case.[1809]

928. TAPS distinguishes NERC reliability penalties as part of a congressionally mandated regimen, whereas the proposed penalties are not.[1810] TAPS notes that, while NERC reliability penalty amounts are used to offset operational costs of NERC or other relevant entities, the NOPR proposes to distribute penalty costs back to interconnection customers, who are not required to use those funds to offset costs for consumers or ratepayers.

929. TAPS also seeks clarification because the NOPR proposal provided that penalties should not be recoverable in transmission rates but also noted that penalties imposed on

[1807] MISO Initial Comments at 14, 74-75.

[1808] AEE Initial Comments at 29; APPA-LPPC Initial Comments at 22; Clean Energy States Initial Comments at 9-10; ISO/RTO Council Initial Comments at 3-4; NESCOE Reply Comments at 12-13; Omaha Public Power Initial Comments at 11; Public Interest Organizations Initial Comments at 35; WIRES Initial Comments at 11.

[1809] NESCOE Reply Comments at 12 n.44 (citing *Reliability Standard Compliance & Enf't in Regions with Reg'l Transmission Orgs. or Indep. Sys. Operators*, 122 FERC ¶ 61,247, at P 16 (2008)).

[1810] TAPS Initial Comments at 5 (citing 16 U.S.C. 824o).

RTOs/ISOs could be handled similarly to NERC reliability penalties, which the Commission has previously allowed RTOs/ISOs to recover from ratepayers.[1811] TAPS contends that the Commission should not allow RTOs/ISOs to pass penalties through to ratepayers or LSEs; to the extent the Commission allows RTOs/ISOs to recover costs through FPA section 205 proceedings, TAPS recommends that the Commission automatically waive any penalty amount the RTO/ISO would otherwise pass to ratepayers.[1812]

930. Commenters argue that the proposed penalty structure lacks the due process and fact finding associated with the RTO/ISO recovery of NERC reliability penalties.[1813] MISO and ISO/RTO Council explain that NERC uses a fact-finding tribunal, which avoids the potential conflicts of interest and process disruptions that would stem from requiring the transmission provider to judge disputes.[1814] Indicated PJM TOs explain that RTOs/ISOs can only recover NERC reliability penalties from another entity if that entity was identified and allowed to participate in the NERC process.[1815] Commenters note that NERC reliability penalty amounts are calculated based on specific circumstances and that

[1811] *Id.* at 3-5.

[1812] *Id.* at 7-8.

[1813] Indicated PJM TOs Initial Comments at 43-44; ISO/RTO Council Initial Comments at 2; MISO Initial Comments at 15, 76; NYISO Initial Comments at 35-36.

[1814] ISO/RTO Council Initial Comments at 6; MISO Initial Comments at 15, 75-76.

[1815] Indicated PJM TOs Initial Comments at 43.

financial penalties are not always imposed.[1816] Further, the ISO/RTO Council argues that the NOPR proposal to allow FPA section 205 filings to allocate penalties is unworkable because it assumes the RTO/ISO will be able to identify a transmission owner that is responsible for the delay.[1817]

931. ISO-NE and MISO explain that transmission providers are in no position to perform fact-finding, which would require a time- and resource-consuming process to hear from all involved parties.[1818] MISO states that it has no procedures beyond its alternative dispute resolution process for adjudicating disputes and even these procedures call for multi-month processes.[1819] MISO notes that it is unclear who would make the findings and how penalties would be assigned if multiple parties contribute to a delay.[1820] MISO and ISO/RTO Council note that the personnel able to determine the cause of a delay are the interconnection study engineers, who would need to divert their resources from performing studies to provide evidence.[1821]

932. MISO TOs state that, if the Commission adopts penalties, it should also adopt the requirement that RTOs/ISOs make an FPA section 205 filing before allocating any

[1816] ISO/RTO Council Initial Comments at 7; MISO Initial Comments at 15, 76-77; NYISO Initial Comments at 36.

[1817] ISO/RTO Council Initial Comments at 4.

[1818] ISO-NE Initial Comments at 36; MISO Initial Comments at 15, 75.

[1819] MISO Initial Comments at 15, 75.

[1820] *Id.* at 76.

[1821] *Id.*; ISO/RTO Council Initial Comments at 7.

penalties to a transmission owner in order to provide due process to the transmission owner and to be consistent with the Commission's approach to RTO/ISO recovery of NERC reliability penalty costs.[1822]

933. Indicated PJM TOs argue that it is unclear whether PJM has the authority to recover penalty costs from transmission owners.[1823] Indicated PJM TOs state that the consolidated transmission owners agreement (CTOA) specifies that PJM has the right to file "charges for recovery of PJM costs" under FPA section 205, but they argue that penalties are not a cost of operation. Indicated PJM TOs explain that the CTOA reserves rights not specifically transferred to PJM to transmission owners. Therefore, Indicated PJM TOs conclude that the right to recover penalties was not conferred on PJM and that PJM lacks the contractual authority to seek recovery of penalties from transmission owners under FPA section 205. Indicated PJM TOs add that modifying the CTOA would implicate the *Mobile-Sierra* presumption.[1824]

934. Further, Indicated PJM TOs argue that the Commission lacks the authority under FPA section 205 to require RTOs/ISOs to seek cost recovery of interconnection study

[1822] MISO TOs Initial Comments at 26.

[1823] Indicated PJM TOs Initial Comments at 44-45.

[1824] *Id.* at 45 n.126 (citing *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527 (2008); *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010)).

penalties.[1825] SEIA disagrees and asks the Commission to establish a regime in which it can recover penalties for late studies in Order No. 890.[1826]

(e) <u>Study Deadline Extension</u>

935. Several commenters support the NOPR proposal to allow for the extension of a study deadline by mutual agreement.[1827] Some commenters argue that this extension will promote cooperation between interconnection customers and transmission providers.[1828] Further, AEE argues that the extension option will provide a buffer for studies that warrant more time and that the two study cycle transition will give transmission providers time to adjust to the cluster model and deadlines, to understand possible variability in each cluster, and to develop strategies for times when extra bandwidth is needed, such as hiring third-party assistance.[1829] AEE suggests that the Commission require that the mutual agreements be publicly available.[1830]

[1825] *Id.* at 45 (citing *Atl. City Elec. Co. v. FERC*, 329 F.3d 856, 859 (D.C. Cir. 2003) (per curiam)).

[1826] SEIA Reply Comments at 13.

[1827] Consumers Energy Initial Comments at 6; NEPOOL Initial Comments at 16; Pine Gate Initial Comments at 38.

[1828] Consumers Energy Initial Comments at 7.

[1829] AEE Reply Comments at 30-31.

[1830] AEE Initial Comments at 31-32.

936. NARUC supports the proposal so long as the transmission provider certifies to the Commission that the extension will not delay unrelated interconnection requests outside the cluster.[1831]

937. Several commenters propose modifications to the NOPR deadline extension proposal. NYISO states that it is unreasonable to allow individual interconnection customers to veto extensions and instead proposes that 30-day extensions should be available if the RTO/ISO notifies the Commission that there is good cause to take additional time to complete the study.[1832] Indicated PJM TOs argue that it will be virtually impossible to obtain mutual agreement in a region with a large number of interconnection customers and instead propose that the transmission provider determine the appropriate extension on compliance.[1833] Tri-State notes that there is no incentive for interconnection customers who have agreed to a study deadline to re-negotiate and mutually agree upon an extended deadline.[1834] SoCal Edison suggests that the Commission allow transmission providers to extend study deadlines in the event of a larger than usual cluster.[1835]

[1831] NARUC Initial Comments at 15.

[1832] NYISO Initial Comments at 42.

[1833] Indicated PJM TOs Initial Comments at 42.

[1834] Tri-State Initial Comments at 19.

[1835] SoCal Edison Initial Comments at 18.

(f) Transition

938. Duke Southeast Utilities request that the Commission clarify that transmission providers already using a cluster study process will not be subject to penalties until after the completion of two study cycles, which will encourage transmission providers not to employ an unnecessary transition process.[1836] Other commenters argue that financial penalties should be in effect during the first transitional cluster study.[1837]

(g) Force Majeure Exception

939. Several commenters support the NOPR proposal to only permit exceptions to the penalty in instances of *force majeure*, arguing that additional exceptions make the penalty less effective.[1838] Invenergy argues that there should be a process for transmission providers to declare *force majeure* to prevent the overuse of this exception.[1839] CREA and NewSun argue that any *force majeure* exception should also apply to interconnection customers when they fail to meet deadlines.[1840]

940. Many commenters argue that the Commission should extend exemptions beyond *force majeure*, such as to events outside the transmission provider's control or for good

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[1836] Duke Southeast Utilities Initial Comments at 11.

[1837] ACE-NY Initial Comments at 13; AEE Initial Comments at 32; Cypress Creek Initial Comments at 24.

[1838] Cypress Creek Initial Comments at 24; Google Reply Comments at 3.

[1839] Invenergy Initial Comments at 31-32.

[1840] CREA and NewSun Initial Comments at 84-85.

cause.[1841] NARUC and National Grid argue that transmission providers should have an opportunity to request a penalty exemption on a case-by-case basis.[1842] NESCOE argues that the Commission should provide a list of presumptive no-fault delays.[1843]

(h) Requests for Alternatives, Clarification, or Technical Conference

941. A number of commenters suggest that the Commission evaluate whether the other reforms are successful before implementing a penalty regime.[1844] NYTOs and Eversource similarly ask that the Commission allow the changes in the ANOPR to take effect before imposing penalties.[1845] Some commenters suggest that the Commission hold a technical conference prior to penalties becoming effective to discuss experiences

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[1841] Indicated PJM TOs Initial Comments at 42; MISO TOs Initial Comments at 25; National Grid Initial Comments at 32; NESCOE Initial Comments at 16; NYISO Initial Comments at 42; PPL Initial Comments at 19; SoCal Edison Initial Comments at 19; Tri-State Initial Comments at 18; WIRES Initial Comments at 10; Xcel Initial Comments at 38.

[1842] NARUC Initial Comments at 21; National Grid Initial Comments at 33.

[1843] NESCOE Initial Comments at 16.

[1844] AEP Initial Comments at 29; Avangrid Reply Comments at 14; Clean Energy Buyers Initial Comments at 10-11; Eversource Initial Comments at 30-31; Idaho Power Initial Comments at 10; ISO/RTO Council Reply Comments at 5; Longroad Energy Reply Comments at 15; NY Commission and NYSERDA Initial Comments at 6; NYISO Initial Comments at 30; Pacific Northwest Utilities Initial Comments at 9-10; PacifiCorp Initial Comments at 34; Puget Sound Initial Comments at 11; State Agencies Initial Comments at 14; TAPS Initial Comments at 9.

[1845] Eversource Initial Comments at 30-31; NYTOs Initial Comments at 23-24.

with the new cluster study process and focus the penalties on the causes of delays.[1846] SPP and NYISO also note that some transmission providers are undergoing their own interconnection queue reform efforts; therefore, the Commission should focus on ensuring those efforts are successful instead of imposing automatic penalties.[1847] TAPS suggests that the Commission delay implementation of penalties by at least five years from the effective date of compliance filings to the final rule.[1848]

942. NARUC argues that any penalty structure should be applied equally to transmission providers delaying interregional affected system studies and seeks clarification on how penalties will be assessed when delays are caused by affected systems.[1849]

943. Some commenters suggest that, instead of or in addition to penalties, the Commission could improve reporting by issuing Commission staff reports or requiring additional reporting from transmission providers.[1850] Indicated PJM TOs explain that the

[1846] ISO/RTO Council Initial Comments at 9; NARUC Initial Comments at 15-22; NESCOE Reply Comments at 14; PJM Initial Comments at 9; TAPS Initial Comments at 9.

[1847] NYISO Initial Comments at 30; SPP Initial Comments at 14-15.

[1848] TAPS Initial Comments at 9.

[1849] NARUC Initial Comments at 14, 17.

[1850] *Id.* at 16; AEE Initial Comments at 32-33; AEE Reply Comments at 32; APPA-LPPC Initial Comments at 23; Avangrid Initial Comments at 31; Bonneville Initial Comments at 16; Clean Energy Associations Initial Comments at 47; Clean Energy Buyers Initial Comments at 11; CREA and NewSun Initial Comments at 85-86; EPSA Initial Comments at 11; Fervo Energy Initial Comments at 6; Google Reply Comments at 4; MISO TOs Initial Comments at 27; National Grid Initial Comments at 31-32;

Commission or an interested party could initiate an FPA section 206 proceeding if it believes PJM is not exercising due diligence in performing studies based on its reporting.[1851] In response to arguments that entities could pursue FPA section 206 filings before the Commission if they believe reasonable efforts have been violated, New Jersey Commission argues that study delays result from systemic failures, so it is inappropriate to address such issues through individual FPA section 206 filings.[1852]

944. MISO proposes that, if a transmission provider misses a deadline by more than a threshold grace period, the transmission provider should be required to self-report the circumstances around the delay to the Commission, and, in response to that self-report, the Commission could issue a show cause order to require the transmission provider and any other relevant entities to respond with specific information about the causes for the delays and propose a mitigation plan.[1853] MISO states that, at the conclusion of the show cause proceeding, the Commission would issue an order that could require transmission providers, transmission owners, or other entities to take specific actions to mitigate the

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NESCOE Reply Comments at 14; NYISO Initial Comments at 31, 43; NYISO Reply Comments at 10; NYTOs Initial Comments at 23; OMS Initial Comments at 15; PacifiCorp Initial Comments at 35; PacifiCorp Reply Comments at 6; Pine Gate Initial Comments at 41; PG&E Initial Comments at 4, 9; R Street Initial Comments at 14; Shell Initial Comments at 11; TAPS Initial Comments at 9; UMPA Initial Comments at 7.

[1851] Indicated PJM TOs Initial Comments at 41.

[1852] New Jersey Commission Reply Comments at 5.

[1853] MISO Initial Comments at 79-80; *see also* MISO TOs Initial Comments at 27 (explaining that targeted intervention through a show cause order is more appropriate than broadly applicable penalties).

delay, require process changes, and/or impose penalties.[1854] MISO argues that its proposal has several advantages over the NOPR penalty proposal, including providing accountability tied to entities actually causing the delay, as determined by the Commission. Public Interest Organizations support the self-reporting concept but do not support conditioning penalty assignment on a show cause proceeding, arguing that this would be administratively burdensome.[1855] AEE also states that MISO's approach could be helpful if paired with binding timelines and a clear penalty structure.[1856]

945. Clean Energy Associations suggest that, if the Commission does not adopt penalties, it should consider requiring remedial action plans, including specific staffing plans, for transmission providers with persistently late or inaccurate studies.[1857]

946. Some commenters argue that the Commission should incentivize transmission providers to meet deadlines rather than penalize them for failing to do so.[1858] Shell proposes that the Commission provide favorable rate treatment for transmission providers that meet study timeliness conditions; specifically, Shell suggests that the Commission

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[1854] MISO Initial Comments at 80-81.

[1855] Public Interest Organizations Reply Comments at 8-9.

[1856] AEE Reply Comments at 38.

[1857] Clean Energy Associations Initial Comments at 45.

[1858] *Id.* at 46; ACE-NY Initial Comments at 14 (recommending a structure with both penalties and incentives); Affected Interconnection Customers Initial Comments at 26 (same); CREA and NewSun Reply Comments at 57 (same); Shell Initial Comments at 10; Longroad Energy Reply Comments at 14; Vermont Electric and Vermont Transco Initial Comments at 2.

create a rebuttable presumption that transmission providers can recover their investments in interconnection queue processing resources if the transmission provider satisfies deadlines at least 90% of the time over two years.[1859] Shell further suggests that these costs can be eligible for inclusion in transmission rate base, with corresponding return on equity, if the transmission provider meets study deadlines at least 95% of the time over two calendar years.[1860] Affected Interconnection Customers propose that the Commission allow RTOs/ISOs to create a monetary incentive for transmission owners that complete their interconnection studies on time.[1861]

947. However, R Street notes that rate incentives, like bonuses on returns on equity, would induce financial motivation but would require a performance baseline that transmission owners could game.[1862] MISO TOs argue that incentives would fail because study delays are caused by factors beyond transmission providers' control.[1863]

948. ACE-NY requests that the Commission clarify whether a failure to meet the *pro forma* LGIP study deadlines would constitute a tariff violation, which could have implications for executive and staff compensation.[1864] MISO TOs argue that such a

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[1859] Longroad Energy Reply Comments at 14-15; Shell Initial Comments at 11.

[1860] Shell Initial Comments at 11.

[1861] Affected Interconnection Customers Initial Comments at 29-30.

[1862] R Street Initial Comments at 15.

[1863] MISO TOs Reply Comments at 15-16.

[1864] ACE-NY Initial Comments at 13.

proposal has no basis and would constitute an even stricter standard because penalties for tariff violations can amount to over $1 million per day, exceeding the proposed $500 per day proposal.[1865]

949. Clean Energy States and TAPS recommend tying executive compensation to interconnection queue deadlines,[1866] noting that SPP and MISO currently tie compensation to reliability performance.[1867] However, MISO TOs note that the Commission has previously found that it lacks such jurisdiction.[1868]

950. Some commenters argue that the Commission should allow transmission providers to set their own deadlines for interconnection studies because the current deadlines are not reasonable or advocate for regional flexibility.[1869] Some commenters recommend allowing transmission providers to adjust study deadlines based on interconnection queue size.[1870] Public Interest Organizations and Google support such proposals to the extent

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[1865] MISO TOs Reply Comments at 14 (citing 16 U.S.C. sec. 825o-1).

[1866] Clean Energy States Initial Comments at 10-11; CREA and NewSun Reply Comments at 57; TAPS Initial Comments at 8.

[1867] TAPS Initial Comments at 8.

[1868] MISO TOs Reply Comments at 15.

[1869] APPA-LPPC Initial Comments at 21; Bonneville Initial Comments at 16; Indicated PJM TOs Reply Comments at 39; ISO-NE Initial Comments at 35-37; NY Commission and NYSERDA Initial Comments at 5; NYISO Initial Comments at 29, 33.

[1870] Bonneville Initial Comments at 16; Google Reply Comments at 5; NYISO Initial Comments at 29; SEIA Reply Comments at 17.

that the deadlines are subject to Commission review.[1871] AEE does not oppose giving transmission providers flexibility to set their study timelines but requests that the Commission set a maximum allowable study timeline.[1872]

951. National Grid suggests that the Commission adopt a minimum time frame approach, which would start the overall interconnection study timeline upon finalizing the base case study models and provide minimum study time frames for scope and result reviews.[1873]

952. PJM suggests that the transmission provider develop a targeted study completion date based on an analysis of that particular interconnection queue, with the target completion date available for public comment.[1874] PJM states that, under this approach, as studies become delayed further and further past the target date, the transmission provider would be required to meet increasing burdens (e.g., public posting of the missed date, filing a report with the Commission, being subject to FPA section 206 action). PJM states that if, despite the FPA section 206 action, the transmission provider misses a subsequent study deadline at the same level, then the Commission could impose penalties for any proven malfeasance by the transmission provider. PJM also suggests that the Commission could allow transmission providers to cap the number of interconnection

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[1871] Public Interest Organizations Reply Comments at 9.

[1872] AEE Reply Comments at 38.

[1873] National Grid Initial Comments at 31.

[1874] PJM Initial Comments at 59-61.

requests in a given cluster to an amount commensurate with available resources. In response, AEE argues that PJM's proposed approach would cause unnecessary administrative burden, which could further harm interconnection customers.[1875]

953. Some commenters claim that the NOPR proposal is vague and raises profound implementation issues (e.g., how or whether the penalty structure will accommodate different cluster sizes, study complexities, or restudies).[1876] R Street suggests, and ISO/RTO Council agrees, that the Commission and stakeholders would benefit from a root cause analysis to identify the cause of study delays, which could inform more reasonable performance expectations.[1877]

954. Some commenters seek clarity regarding who bears financial penalties for late affected system studies and related affected system obligations.[1878] ENGIE states that it is unclear who bears the financial penalties for late affected system studies.[1879] In contrast, MISO interprets the NOPR proposal to apply penalties only to the affected

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[1875] AEE Reply Comments at 38-39.

[1876] EEI Reply Comments at 17; Eversource Initial Comments at 20, 28.

[1877] ISO/RTO Council Reply Comments at 5; R Street Initial Comments at 14.

[1878] Duke Southeast Utilities Initial Comments at 17-18; ENGIE Initial Comments at 9; MISO Initial Comments at 92.

[1879] ENGIE Initial Comments at 9. Additionally, ENGIE states that transmission owners typically have responsibilities for affected system studies and, therefore, argues that the Commission should consider language that distributes financial risk and penalties to both transmission owners and transmission providers, including an ability for transmission providers to recover costs from transmission owners. *Id.*

system operator, though MISO also recommends that the Commission recognize that some delays may be beyond the control of the affected system operator and recommends that affected system operators not be penalized for third-party delays.[1880] Similarly, Duke Southeast Utilities express concern that penalties could be levied against affected system operators for delays beyond their control and further argue that, instead of unilaterally imposing financial penalties on one entity, which, to Duke Southeast Utilities, seems arbitrary and unfounded, the Commission should consider imposing multilateral penalties on all entities in accordance with their individual obligations set forth in the proposed process.[1881]

955. Cypress Creek suggests that, in addition to financial penalties for missed study deadlines, the Commission should also impose penalties for inaccurate study results.[1882] AEE and Clean Energy Associations argue that the Commission should provide guidelines and reporting requirements regarding acceptable study accuracy.[1883]

[1880] MISO Initial Comments at 92. WAPA also is generally concerned about the imposition of monetary penalties for failure to meet deadlines and questions whether federal agencies like WAPA should or even can be subject to monetary penalties. *See* WAPA Initial Comments at 10, 14.

[1881] Duke Southeast Utilities Initial Comments at 17-18.

[1882] Cypress Creek Initial Comments at 23.

[1883] AEE Initial Comments at 34; Clean Energy Associations Initial Comments at 47.

956. CREA and NewSun propose an overall "reasonableness" standard to ensure the quality of the studies and that there is no ongoing failure to provide adequate staffing or to employ reasonable study assumptions.[1884]

957. National Grid argues that the Commission should permit transmission providers to assign a dedicated person to monitor the progress of each entity (i.e., interconnection customer, transmission owner, and RTO/ISO) during the interconnection process.[1885] National Grid argues that the cost of this person and any other additional costs needed to satisfy the NOPR proposal should be recoverable in rates so that transmission providers would be able to recover costs incurred to reduce penalty risk.

958. Some commenters suggest that the Commission allow third-party consultants to complete studies, which would conserve transmission provider resources and provide a pathway for interconnection customers to move forward.[1886] Dominion argues in response that there is a general lack of qualified professionals to perform interconnection studies, so a third party will not have access to the personnel, knowledge, or resources to perform them.[1887]

[1884] CREA and NewSun Initial Comments at 85.

[1885] National Grid Initial Comments at 33.

[1886] AEE Initial Comments at 34; Clean Energy Associations Initial Comments at 46; Public Interest Organizations Reply Comments at 4; SEIA Initial Comments at 33.

[1887] Dominion Reply Comments at 19-20.

959. Pacific Northwest Utilities argue that the reasonable efforts standard should not be eliminated for facilities studies, which require an individual study, noting that the number of facilities studies needed can vary greatly between clusters.[1888]

960. NYISO suggests that the Commission adopt features of the NERC model, including the use of non-financial sanctions for minor or excusable violations and penalty reductions for cooperative and remedial actions.[1889]

961. Tri-State supports the NOPR proposal not to assess financial penalties until one cluster study cycle (that is not a transitional study cycle) after the compliance effective date. Tri-State seeks clarification on when penalties would be imposed for transmission providers already using a cluster study process.[1890]

c. **Commission Determination**

962. We adopt the NOPR proposal to eliminate the reasonable efforts standard set forth in sections 2.2, 3.5.4(i), 7.4, 8.3, and Attachment A to Appendix 4 of the *pro forma* LGIP. In its place, we adopt the NOPR proposal, with modification, to add new section 3.9 to the *pro forma* LGIP that imposes study delay penalties, as further discussed below: delays of cluster studies beyond the tariff-specified deadline will incur a penalty of $1,000 per business day; delays of cluster restudies beyond the tariff-specified deadline will incur a penalty of $2,000 per business day; delays of affected system studies beyond

[1888] Pacific Northwest Utilities Initial Comments at 11-12.

[1889] NYISO Initial Comments at 41-42.

[1890] Tri-State Initial Comments at 19.

the tariff-specified deadline will incur a penalty of $2,000 per business day; and delays of facilities studies beyond the tariff-specified deadline will incur a penalty of $2,500 per business day.[1891]

963. As explained in greater detail in this Section, we adopt the following features of the study delay penalty structure for late interconnection studies: (1) no study delay penalties will be assessed until the third cluster study cycles (including any transitional cluster study cycle, but not transitional serial studies) after the Commission-approved effective date of the transmission provider's filing in compliance with this final rule; (2) there will be a 10-business day grace period, such that no study delay penalties will be assessed for a study that is delayed by 10 business days or fewer; (3) deadlines may be extended for a particular study by 30 business days by mutual agreement of the transmission provider and all interconnection customers with interconnection requests in the relevant study; (4) study delay penalties will be capped at 100% of the initial study deposits received for all of the interconnection requests in the cluster for cluster studies and cluster restudies, 100% of the initial study deposit received for the single interconnection request in the study for facilities studies, and 100% of the study deposit(s) that the transmission provider acting as an affected system operator (affected system transmission provider) collects for conducting the affected system study; (5) transmission providers will have the ability to appeal any study delay penalties to the

[1891] The penalties that we adopt in this final rule in section 3.9 of the *pro forma* LGIP for late affected system studies only apply to affected system operators that are public utilities.

Commission, with the Commission determining whether good cause exists to grant the relief requested on appeal; (6) transmission providers must distribute study delay penalties to interconnection customers in the relevant study on a pro rata per interconnection request basis to offset their study costs; (7) non-RTO/ISO transmission providers and transmission-owning members of RTOs/ISOs may not recover study delay penalties through transmission rates; (8) RTOs/ISOs may submit an FPA section 205 filing to propose a default structure for recovering study delay penalties and/or to recover the costs of any specific study delay penalties;[1892] (9) transmission providers must pay the penalty for each late study on a pro rata basis per interconnection request to all interconnection customers or affected system interconnection customers included in the relevant study that did not withdraw, or were not deemed withdrawn, from the interconnection queue before the missed study deadline; and (10) transmission providers must post quarterly on their OASIS or other publicly accessible website (a) the total amount of study delay penalties from the previous reporting quarter and (b) the highest study delay penalty paid to a single interconnection customer in the previous reporting quarter. We also add new section (f)(1) to 18 CFR section 35.28(f)(1)(ii) to specify that any public utility that conducts interconnection studies shall be liable for and eligible to appeal penalties following that public utility's failure to complete an interconnection

[1892] We note that the typical standard of review under FPA section 205 would apply to these filings: i.e., the filer must show that any proposal to recover study delay penalties is just, reasonable, and not unduly discriminatory or preferential. *See* 16 U.S.C. 824d.

study by the appropriate deadline. We also decline to adopt the NOPR's proposed *force majeure* penalty exception. We first discuss our overarching rationale for this set of reforms, and then discuss each of these reforms in greater detail and our rationale for each.

964. We adopt these reforms to remedy the unjust and unreasonable rates stemming from interconnection queue backlogs and to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. Specifically, these reforms will help ensure more timely processing of interconnection requests by incentivizing transmission providers to meet interconnection study deadlines.[1893]

i. Eliminating the Reasonable Efforts Standard

965. We adopt the NOPR proposal to eliminate the reasonable efforts standard set forth in sections 2.2, 3.5.4(i), 7.4, 8.3, and Attachment A to Appendix 4 of the *pro forma* LGIP. In these revised sections, we specifically eliminate the reasonable efforts standard for conducting cluster studies, cluster restudies, facilities studies, and affected system studies.

966. The lengthy interconnection study delays and interconnection queue backlogs throughout the country support our conclusion that the reasonable efforts standard does not provide an adequate incentive for transmission providers to complete interconnection

[1893] Invenergy Initial Comments at 30; Iowa Commission Initial Comments at 5-6 ("RTOs/ISOs need to prioritize interconnection studies and need to hold their employees and/or outside entities responsible for delays"); SEIA Initial Comments at 32.

studies on time. As discussed in Section II above, transmission providers are experiencing significant interconnection queue backlogs, as evidenced, for example, by their Order No. 845 reports.[1894] There is every reason to believe that many of the factors contributing to significant interconnection queue backlogs and delay—including the rapidly changing resource mix, market forces, and emerging technologies—will persist. In response to those ongoing challenges, we find that it is just, reasonable, and not unduly discriminatory or preferential to eliminate the reasonable efforts standard and adopt a penalty structure that reasonably incentivizes transmission providers to ensure the timely processing of interconnection requests. We note that we are not finding that transmission providers have necessarily acted in bad faith or that their actions are the sole reason for the queue delays. Indeed, throughout this final rule, we adopt numerous reforms to appropriately incentivize interconnection customers to help reduce interconnection delays that may result from their conduct. Nevertheless, we find that the elimination of the reasonable efforts standard and the adoption of penalties for late studies are needed to

[1894] *See* Appendix B to this final rule (showing that over 2,800 interconnection studies were delayed as of the end of Q4 2022 and that over 1,900 interconnection studies were delayed as of the end of Q4 2021); *see also* Queued Up 2023 at 6 (showing growth in number of interconnection requests from 2013 to 2022) and Queued Up 2023 at 3 (noting that generating facilities built in 2008 spent, on average, less than two years in interconnection queues, whereas generating facilities built in 2022 spent, on average, five years in interconnection queues). Although some commenters argue that Order No. 845 data do not provide sufficient support (AEP Initial Comments at 25-26; MISO Initial Comments at 72), the data demonstrate that interconnection queue delays have continued to worsen over recent years and industry reports have similarly concluded that interconnection queues are seeing increasingly severe delays. We cite evidence that contradicts such comments and that, instead, supports our findings. *See, e.g.*, *supra* Section II.C.

create an incentive for transmission providers, which will help reduce interconnection delays and ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.

967. The reasonable efforts standard worsens current-day challenges, as it fails to ensure that transmission providers are keeping pace with the changing and complex dynamics of today's interconnection queues. Contrary to the assertions of some commenters, we believe that there are steps within transmission providers' control, from deploying transmission providers' resources to exploring administrative efficiencies and innovative study approaches,[1895] to better ensure timely processing of interconnection studies to remedy existing deficiencies.

968. As discussed above, we adopt several reforms to address speculative interconnection requests by imposing stricter requirements on interconnection customers for entering and remaining in the interconnection queue (e.g., site control requirements, commercial readiness deposits, and withdrawal penalties). We also adopt reforms to improve the efficiency of interconnection studies and interconnection queue processing for all transmission providers (e.g., first-ready, first-served cluster study process). In this Section, we adopt reforms to ensure that transmission providers are doing their part as well by eliminating the reasonable efforts standard and imposing study delay penalties on

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[1895] *See* Public Interest Organizations Reply Comments at 4 ("any claim that an individual transmission provider has done absolutely everything in its power to improve the processing rate of interconnection requests… almost certainly comes from a lack of imagination"); R Street Initial Comments at 14 (explaining that advances in computing fields have the potential to reduce queue processing times).

transmission providers when they fail to meet the interconnection study deadlines we adopt in this final rule. Based on the record, we find that the elimination of the reasonable efforts standard and its replacement with firm deadlines and penalties are needed to remedy unjust and unreasonable rates and ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. Thus, we disagree with commenters that contend that the reasonable efforts standard continues to be appropriate or that the Commission's past orders, including Order No. 845, mean that the reasonable efforts standard continues to ensure just and reasonable rates.[1896]

969. We similarly disagree with commenters that support eliminating the reasonable efforts standard but that do not support imposing study delay penalties on transmission providers for failing to meet interconnection study deadlines.[1897] We do not believe that this result would remedy the unjust and unreasonable rates, nor would it ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner by aligning incentives properly.

[1896] *See, e.g.*, Avangrid Initial Comments at 10, 30-31; Bonneville Initial Comments at 16; EEI Reply Comments at 16; Indicated PJM TOs Initial Comments at 36; MISO TOs Reply Comments at 6-7; NYISO Initial Comments at 30-31; PG&E Reply Comments at 3-4; WIRES Initial Comments at 10.

[1897] CAISO Initial Comments at 25-26; Clean Energy Buyers Initial Comment at 9-10; MISO Initial Comments at 13, 71, 79; Shell Initial Comments at 10; *see also* NARUC Initial Comments at 13-14, 20; Pennsylvania Commission Initial Comments at 2-3 (supporting the proposal to eliminate the reasonable efforts standard but taking no position on the need for monetary penalties).

970. As we are eliminating the reasonable efforts standard, we also must adopt a replacement rate that remedies the problems just described. The sections below set forth a study delay penalty structure and why we believe it is justified. In short, we adopt provisions in the *pro forma* LGIP that impose firm interconnection study deadlines and corresponding study delay penalties on transmission providers that fail to meet those deadlines.

971. Interconnection customers face financial harm when study deadlines are not met, ultimately inhibiting their ability to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. We find that holding transmission providers to firm interconnection study deadlines is likely to accelerate the interconnection study process and provide greater certainty to interconnection customers, allowing them to make more informed business decisions around whether to proceed with or withdraw from the interconnection queue, which will also ultimately improve interconnection queue management and remedy the unjust and unreasonable rates otherwise created by study delays.

972. At the same time, we do not believe that the study delay penalty structure that we adopt in this final rule is unduly harsh for transmission providers, either in penalty amount or the form of its application. The study delay penalty structure adopted in this final rule balances the harm to interconnection customers of interconnection study delays and the associated need to incentivize transmission providers to timely complete interconnection studies with the burdens on transmission providers of conducting interconnection studies and potentially facing penalties for delays, including those that

may be caused or exacerbated by factors beyond their control. In particular, we adopt the following safeguards for transmission providers: (1) a transition period rather than imposing study delay penalties as soon as transmission providers begin implementing the reforms in this final rule; (2) a 10-business day grace period where no study delay penalties will be assessed; (3) a provision that allows a 30-business day deadline extension upon mutual agreement of the transmission provider and interconnection customers; (4) caps on study delay penalties; and (5) a transmission provider ability to appeal. We also adopt provisions governing distribution of study delay penalties to interconnection customers and prohibiting recovery of study delay penalties through transmission rates, along with transparency-related posting requirements to the benefit of interconnection customers and consumers alike. We believe that the study delay penalty structure adopted herein aligns transmission provider and interconnection customer incentives while providing appropriate built-in flexibility and safeguards for transmission providers, thereby achieving a balance that ensures just and reasonable rates and ensures that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

ii. <u>Penalty Amount</u>

973. We modify the *pro forma* LGIP to adopt a study delay penalty structure whereby penalties increase through the interconnection study process. Delays of cluster studies beyond the tariff-specified deadline will incur a penalty of $1,000 per business day; delays of cluster restudies beyond the tariff-specified deadline will incur a penalty of $2,000 per business day; delays of affected system studies beyond the tariff-specified

deadline will incur a penalty of $2,000 per business day; and delays of facilities studies beyond the tariff-specified deadline will incur a penalty of $2,500 per business day.

974. We agree with the numerous commenters who argue that the NOPR penalty proposal of $500 per business day is too low to create an incentive for transmission providers to meet study deadlines.[1898] We find it necessary to modify the NOPR proposal to establish a higher penalty amount and a structure of increasing penalties that reflects the greater harm caused by delayed studies at later interconnection stages.

975. We reach this conclusion for several reasons. First, we find persuasive the comments asserting that a penalty of $500 per business day is insufficient to incentivize transmission provider actions that will reduce the incidence of study delays.[1899] At $500

[1898] ACE-NY Initial Comments at 12; Affected Interconnection Customers Initial Comments at 24-26; CESA Initial Comments at 11; CESA Reply Comments at 8-9; Clean Energy Associations Initial Comments at 44; Consumers Energy Initial Comments at 6; CREA and NewSun Reply Comments at 56; Cypress Creek Initial Comments at 24; ELCON Initial Comments at 7-8; EPSA Initial Comments at 11; Fervo Energy Initial Comments at 6; Invenergy Initial Comments at 29; NARUC Initial Comments at 14; Pine Gate Initial Comments at 39.

[1899] *See, e.g.*, Invenergy Initial Comments at 29-30 ("[T]he proposed penalty amount is woefully insufficient to create any real incentive" . . . "While a study that is six months late may severely impact an interconnection customer's development efforts, it would amount to only a $90,000 penalty, which is *de minimis* for transmission providers which may have annual revenues of $25 billion if not more"); Affected Interconnection Customers Initial Comments at 24-25 ("[A] $500 per day penalty imposed upon transmission providers with hundreds of millions, if not billions of dollars of transmission assets, is a drop in the bucket that will be highly unlikely to deter continued missed interconnection study deadlines"); Cypress Creek Initial Comments at 24 ("[P]enalties should . . . be substantially larger so that they serve as meaningful deterrents to delayed and inaccurate study results"); Pine Gate Initial Comments at 39 ("A daily penalty rate that is too low will do little to incentivize transmission providers to complete studies in a timely manner, even in a situation where the penalty equals the full 100 percent of total

per business day, a study that is delayed by six months—or roughly 126 business days—would produce a penalty of only $63,000. We view such a penalty as insufficient considering that the purpose of the penalty is to incentivize timely study completion that may be achieved, for example, by hiring additional personnel or investing in new software.

976. Some commenters advocate for penalty amounts that more closely approximate the costs that delays impose in interconnection customers,[1900] while others propose penalty amounts ranging from $2,500 per day to $7,000 per day.[1901] Based on the record before us, we believe the $1,000/$2,000/$2,500 per business day penalty structure, combined with the transition, grace period, cap on penalties, and ability to appeal that we adopt below, strikes an appropriate balance because it creates an incentive for transmission providers to meet study deadlines while not being overly punitive.

977. Second, adopting progressively higher penalty amounts for delayed cluster restudies and facilities studies reflects the progressively greater harm to interconnection customers of delayed studies at those later stages—at which they will have made greater investments in advancing their projects toward commercial development through steps such as obtaining site control, securing permits, and contracting for equipment. This is

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study deposits received”).

[1900] Cypress Creek Initial Comments at 24; Pine Gate Initial Comments at 39-40.

[1901] ACE-NY Initial Comments at 12; Affected Interconnection Customers Initial Comments at 5, 26; CESA Reply Comments at 9; Invenergy Initial Comments at 30.

especially true given the new site control requirements, commercial readiness deposits, and withdrawal penalties we adopt in this final rule, which also become increasingly stringent as the study process progresses. These reforms will require that interconnection customers have greater capital at risk at each stage to affirm their commitment to reaching commercial operation. We find it appropriate that transmission providers face study delay penalties structured in a similar manner to provide adequate incentives to complete interconnection studies on time.

978. Third, the penalty structure we adopt here will impose more stringent study delay penalties at later stages when reasons for study delays should be fewest. That is, we expect the volume of interconnection requests to decrease as they progress through the study process, with fewer interconnection requests reaching the cluster restudy and facilities study stages. This reduction in volume will reduce the likelihood transmission providers are unable to complete those studies on time. We find it reasonable to hold transmission providers most accountable for timely study completion in the stages where delays should be most avoidable.

iii. Transition

979. We modify proposed section 3.9(6) of the *pro forma* LGIP, which provided that no study delay penalties shall be assessed until one cluster study cycle (that is not a transitional study cycle) after the Commission-approved effective date of the transmission provider's filing in compliance with this final rule. Instead, we modify that section to provide that no study delay penalties shall be assessed until the third cluster study cycle after the Commission-approved effective date of the compliance filing

(including any transitional cluster study cycle, but not transitional serial studies).[1902] We believe that giving transmission providers time to adapt to the new processes without imposing study delay penalties immediately will help ensure that transmission providers' implementation of this final rule has begun to reduce backlogged interconnection queues: i.e., we expect transmission providers to meet the interconnection study deadlines once they are implementing the cluster study process, with the increased requirements on interconnection customers (e.g., site control requirements, commercial readiness deposits, and withdrawal penalties) to help prevent speculative interconnection requests from entering and remaining in the interconnection queue.

980. We adopt Duke Southeast Utilities' request to specify that transmission providers already using a cluster study process will not be subject to penalties until the third cluster study cycle after the Commission-approved effective date of the transmission provider's filing in compliance with this final rule.[1903] We agree that transmission providers that already use a cluster study process should not be incentivized to employ an unnecessary transition process in response to this final rule simply to delay the possibility of study delay penalties. Accordingly, we modify the NOPR proposal such that no transmission providers will be assessed study delay penalties until the third cluster study cycle after the Commission-approved effective date of the compliance filing.

[1902] *See supra* Section III.A.7.c regarding the transition to the cluster study process.

[1903] Duke Southeast Utilities Initial Comments at 11.

iv. Grace Period

981. In addition to adopting a study delay penalty amount that we believe balances incentivizing transmission providers while not being overly punitive, we adopt in *pro forma* LGIP section 3.9(4) a 10-business day grace period, such that no study delay penalties will be assessed for a study that is delayed by 10 business days or fewer, and if the study is delayed by more than 10 business days, the penalty amount will be calculated from the first business day the transmission provider exceeds the applicable study deadline. We believe that this 10-business day grace period will provide an appropriate level of flexibility for transmission providers to address unforeseen circumstances or complexities that arise in the study process. We also believe that this grace period will lessen any administrative burden associated with the appeals process or RTO/ISO recovery of study delay penalty costs, as studies with short delays will not incur study delay penalties that may trigger appeals filings or the need for RTO/ISO penalty recovery.

v. Study Deadline Extension

982. We adopt the NOPR proposal in *pro forma* LGIP section 3.9(5) to allow extensions of the deadline for a particular study by 30 business days by mutual agreement of the transmission provider and all interconnection customers with interconnection requests in the relevant study. We believe that this reform will promote cooperation between transmission providers and interconnection customers and incentivize transmission providers to keep interconnection customers informed of the status of study processes.

983. We decline to adopt AEE's suggestion to require transmission providers to publicly post when a study deadline is extended by mutual agreement.[1904] We do not find it necessary to require such public posting because transmission providers are being given sufficient incentive to minimize delays and manage all interconnection studies fairly. We also decline to adopt NARUC's suggestion to require transmission providers to certify that extensions will not delay unrelated interconnection requests outside the cluster.[1905] Transmission providers will be sufficiently incentivized to ensure that such extensions do not delay other studies because any such delays may incur study delay penalties, as described in this Section. In response to commenters that argue that it will be difficult to obtain mutual agreement in large regions, we do not view that as a reason to decline to adopt or to modify the proposal.[1906] If an interconnection study is delayed, and mutual agreement cannot be obtained, the transmission provider will be assessed the corresponding study delay penalties and may file an appeal with the Commission to explain any relevant circumstances.

vi. <u>Cap on Penalties</u>

984. We modify proposed section 3.9(2) of the *pro forma* LGIP, which capped study delay penalties at 100% of the total study deposit received for the late interconnection study, to instead cap penalties at: (1) 100% of the initial study deposits received for all of

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[1904] AEE Initial Comments at 31-32.

[1905] NARUC Initial Comments at 15.

[1906] Indicated PJM TOs Initial Comments at 42; Tri-State Initial Comments at 19.

the interconnection requests in the cluster for cluster studies and cluster restudies;[1907] (2) 100% of the initial study deposit received for the single interconnection request in the study for facilities studies; and (3) 100% of the study deposit(s) that the affected system transmission provider collects for conducting the affected system study. As discussed in the Section III.A.2.6.a above, we modify the NOPR proposal and require transmission providers to collect a single study deposit from interconnection customers only upon entry into the cluster (initial study deposit), rather than a study deposit at each phase of the study process, as proposed in the NOPR. Accordingly, we modify the study delay penalty cap to reflect this change in the study deposit requirements. By tying the study delay penalty cap to the study deposits, we ensure that the maximum penalty bears a relationship to the costs of the study that was late and is not unnecessarily punitive.

985. In response to commenters who argue that study delay penalties should not be capped,[1908] or that the cap should be higher than 100% of the study deposits for the late interconnection study,[1909] we believe that imposing study delay penalties that exceed the

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[1907] Under section 3.1.1.1 of the *pro forma* LGIP, initial study deposits will range from $25,000 to $250,000, depending on the size of the proposed generating facility.

[1908] ACE-NY Initial Comments at 13; AEE Reply Comments at 37; Consumers Energy Initial Comments at 6; CREA and NewSun Initial Comments at 84; Cypress Creek Initial Comments at 23-24; Public Interest Organizations Initial Comments at 35-36; SEIA Initial Comments at 34.

[1909] Interwest Initial Comments at 8; Invenergy Initial Comments at 31; Northwest and Intermountain Initial Comments at 14.

amount of the study deposit collected for the late interconnection study will be unnecessarily punitive to transmission providers.

986. In response to Invenergy's request for clarification, we confirm that the cap will not be impacted by any withdrawal penalties.[1910]

vii. Ability to Appeal

987. We further modify the NOPR proposal to include, in section 3.9(3) of the *pro forma* LGIP, the ability for transmission providers to appeal any study delay penalties to the Commission.[1911] Any such appeal must be filed no later than 45 calendar days after the late study has been completed. The Commission will evaluate whether good cause exists to grant relief from the study delay penalty and will issue an order granting or denying relief. In evaluating whether there is good cause to grant such relief, the Commission may consider, among other factors: (1) extenuating circumstances outside the transmission provider's control, such as delays in affected system study results; (2) efforts of the transmission provider to mitigate delays; and (3) the extent to which the transmission provider has proposed process enhancements either in the stakeholder

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[1910] Invenergy Initial Comments at 31.

[1911] We note that these appeals should not be filed under FPA section 206. *Contra Hanwha Q-CELLS USA Corp.*, 174 FERC ¶ 61,013, at PP 9-10 (2021) (interpreting CAISO's open access transmission tariff provision, which allows market participants that receive specific CAISO-imposed sanctions to obtain immediate review of CAISO's determination by directly appealing to the Commission "in accordance with [the Commission's] rules and procedures," as a reference to Rule 206 and Rule 218); *Mission Solar LLC*, 174 FERC ¶ 61,014, at PP 10-11 (2021); *Cal. Indep. Sys. Operator Corp.*, 184 FERC ¶ 61,009, at P 24 (2023).

process or at the Commission to prevent future delays. The filing of an appeal will stay the transmission providers' obligation to distribute the study delay penalty funds to interconnection customers until 45 calendar days after (1) the deadline for filing a rehearing request has ended, if no requests for rehearing of the Commission's decision on the appeal have been filed, or (2) the date that any requests for rehearing of the Commission's decision on the appeal are no longer pending before the Commission.

988. By providing an appeal process, we balance the need to ensure that transmission providers have an incentive to meet interconnection study deadlines with protections to ensure that any such penalties are fair and not triggered if good cause justifies the delay. The protections embedded in this appeal process address commenters' concerns that there be adequate due process and/or fact-finding before imposing a study delay penalty on transmission providers.[1912]

989. In response to commenters that oppose study delay penalties because interconnection study delays are often caused by factors outside transmission providers' control,[1913] we note that the penalties adopted herein are an integral element of a just and

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[1912] Indicated PJM TOs Initial Comments at 43-44; ISO/RTO Council Initial Comments at 2; MISO Initial Comments at 15, 76; NYISO Initial Comments at 35-36.

[1913] AEP Initial Comments at 25-26; Ameren Initial Comments at 20; Avangrid Initial Comments at 9-10, 29; Dominion Reply Comments at 19; Indicated PJM TOs Reply Comments at 22-24; ISO-NE Initial Comments at 35-36; ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 73-74; MISO TOs Initial Comments at 15-16, 23-24; National Grid Initial Comments at 30; NESCOE Reply Comments at 11-12; NRECA Initial Comments at 9, 33-34; NYISO Initial Comments at 26-27; OMS Initial Comments at 15; Pacific Northwest Utilities Initial Comments at 9-10; PacifiCorp Initial Comments at 32-35; PG&E Initial Comments at 7; PG&E Reply Comments at 3-4; Puget Sound Initial Comments at 9; SDG&E Reply Comments at 1; Southern Initial Comments

reasonable replacement rate to ensure that transmission providers are properly incentivized to address these factors. We do not find it appropriate to impose penalties only where a factor can be conclusively demonstrated to be within a transmission provider's control, as this would impose significant administrative burden. It may be difficult to precisely determine the cause of any given delay, especially where delay occurs due to multiple factors. Further, transmission providers' concerns are addressed to some extent through the ability to appeal described above, which provides an opportunity for relief from any study delay penalties. Further, we note that many of the reforms adopted in this final rule will help to mitigate factors that may prolong the study process, such as the submission of speculative interconnection requests. In addition, the reforms adopted regarding affected system coordination—discussed later in this final rule—will address delays resulting from affected system studies. We disagree with Indicated PJM TOs that a complete *de novo* review is needed to assess study delay penalties.[1914] We find that the good cause standard adopted in this final rule[1915] provides an adequate framework through which the Commission can evaluate whether it is appropriate to grant relief from any applicable penalties.

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at 5, 30; State Agencies Initial Comments at 12-14; Tri-State Initial Comments at 17-18; U.S. Chamber of Commerce Initial Comments at 10; WIRES Initial Comments at 9; Xcel Initial Comments at 38.

[1914] Indicated PJM TOs Initial Comments at 44.

[1915] *See supra* PP 987-988.

viii. Distribution of Study Delay Penalties to Interconnection Customers

990. We adopt the NOPR proposal, with modification, set forth in *pro forma* LGIP section 3.9(1), to require transmission providers to distribute study delay penalties on a pro rata basis per interconnection request to the interconnection customers and affected system interconnection customers included in the relevant study that did not withdraw, or were not deemed withdrawn, from the interconnection queue before the missed study deadline. Unless the transmission provider files an appeal to the study penalty, the study delay penalty must be distributed no later than 45 calendar days after the late study has been completed. Specifically, a study delay penalty for a delayed cluster study or cluster restudy must be distributed on a pro rata basis per interconnection request to all interconnection customers in the cluster, per the requirements above. A study delay penalty for a delayed facilities study must be distributed to the interconnection customer whose facilities were being studied, per the requirements above. Further, a study delay penalty for a delayed affected system study must be distributed to the affected system interconnection customer(s) whose generating facility was being studied by an affected system transmission provider, per the requirements above. In response to PG&E's request for clarification,[1916] the study delay penalties are on a per business day basis and will be distributed equally to each delayed interconnection customer per the requirements above.

[1916] PG&E Initial Comments at 8.

991. We find the distribution of the study delay penalties imposed due to a delay in the study, which defray the study costs of the interconnection customers affected by that delay, to be just and reasonable, as they will ensure that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner.

ix. No Recovery in Transmission Rates or from Interconnection Customers

992. Regarding recovery of study delay penalties, we modify the NOPR proposal to prohibit non-RTO/ISO transmission providers and transmission-owning members of RTOs/ISOs from recovering study delay penalty amounts through transmission rates. This treatment of study delay penalties is consistent with the treatment of penalties imposed pursuant to Order No. 890[1917] and will ensure that the study delay penalties have the incentivizing effect discussed above. Because the at-fault transmission provider's shareholders will pay the penalty, this prohibition addresses commenters' concerns[1918] that study delay penalty costs will ultimately be borne by customers and ratepayers through increased transmission costs.[1919]

[1917] *See* Order No. 890, 118 FERC ¶ 61,119 at P 1357 ("We will prohibit all jurisdictional transmission providers from recovering penalties for late studies from transmission customers.").

[1918] Alliant Energy Initial Comments at 6-7; National Grid Initial Comments at 33; NYISO Reply Comments at 6-7, 9; R Street Initial Comments at 14; SEIA Reply Comments at 17; State Agencies Initial Comments at 12; Tri-State Initial Comments at 18.

[1919] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 884 ("[B]ecause liquidated damages liability will not have to be paid unless the Transmission Provider is at fault, we conclude that these damages will not be considered just and reasonable costs of service

993. Additionally, we decline to allow any transmission provider to recover study delay penalties from interconnection customers to the extent the interconnection customers cause delays. If a study delay is caused by an interconnection customer, and not the transmission provider, that would represent a potentially compelling basis for the Commission to find that good cause exists to waive the study delay penalties. Further, we note that, in the event that an interconnection request is incomplete or an interconnection customer misses a deadline, those interconnection requests are subject to the withdrawal provisions of *pro forma* LGIP section 3.7.

x. Penalty Recovery in RTOs/ISOs

994. We decline to adopt the NOPR proposal to require RTOs/ISOs to submit requests to recover the costs of specific study delay penalties under FPA section 205. RTOs/ISOs may instead submit an FPA section 205 filing to propose a default structure for recovering study delay penalties and/or make individual FPA section 205 filings to recover the costs of any specific study delay penalties. We believe that this discretion for RTOs/ISOs will reduce the administrative burden associated with study delay penalty cost recovery and will allow RTOs/ISOs the flexibility to craft rules that work for their region. In response to ACORE's recommendation that RTOs/ISOs provide criteria for how they will assign study delay penalties, we note that RTOs/ISOs may file FPA section 205 proposals to explain how they will recover study delay penalties.[1920]

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and will not be recoverable in transmission rates.").

[1920] ACORE Initial Comments at 8.

995. We modify the NOPR proposal to adopt 18 CFR section 35.28(f)(1)(ii) to specify that, for RTOs/ISOs in which the transmission-owning members perform certain interconnection studies, the study delay penalties imposed under the new *pro forma* LGIP will be imposed directly on the transmission-owning member(s) that conducted the late study, thereby mooting the issue of how RTOs/ISOs recover those specific penalties. We believe that this change will also reduce the administrative burden, as RTOs/ISOs will typically not need to seek cost recovery for late facilities studies because those studies are often conducted by transmission-owning members. This change will also ensure that the study delay penalties are imposed on the public utility with the most control over whether the study deadline is met, i.e., the public utility conducting the study. Doing so aligns the incentive created by the study delay penalty with the entity most in control of the study timeline. This change also responds to AEE's suggestion to assign RTO/ISO study delay penalties directly to transmission owners, OPSI's contention that RTOs/ISOs may be reluctant to seek cost recovery from transmission owners, and TAPS' concern that RTOs/ISOs would need well-supported cases to assign study delay penalties to transmission owners.[1921]

996. In response to commenters concerned about how study delay penalties will be assigned if no fault is found among RTO/ISO members,[1922] the study delay penalties are

[1921] AEE Initial Comments at 30; OPSI Initial Comments at 9; TAPS Initial Comments at 6-7.

[1922] Alliant Energy Initial Comments at 6-7; APPA-LPPC Initial Comments at 22; ISO/RTO Council Initial Comments at 4; NARUC Initial Comments at 18; NESCOE

imposed automatically on the RTO/ISO under the *pro forma* LGIP. As explained above, RTOs/ISOs may file an FPA section 205 proposal to recover the costs of study delay penalties. Concerns about any such proposals are best addressed in the relevant FPA section 205 proceedings. For the same reason, we decline to adopt TAPS' recommendation that the Commission provide an automatic waiver of any study delay penalty amount the RTO/ISO would otherwise pass to ratepayers,[1923] as such determinations are best made on a case-by-case basis. In response to Indicated PJM TOs argument that PJM lacks the contractual authority to seek recovery of study delay penalties from transmission owners,[1924] PJM's authority to recover costs from its transmission-owning members can be properly addressed in any future FPA section 205 proceeding.

997. We acknowledge commenters' concerns that the study delay penalty structure may impose an administrative and litigative burden on RTOs/ISOs and the Commission,[1925] and that RTOs/ISOs may be in a fact-finding position in order to be able to assign study

Initial Comments at 16.

[1923] TAPS Initial Comments at 7-8.

[1924] Indicated PJM TOs Initial Comments at 45.

[1925] Avangrid Reply Comments at 8; CAISO Initial Comments at 26; Indicated PJM TOs Reply Comments at 27; ISO-NE Initial Comments at 35; ISO/RTO Council Initial Comments at 3-4; PJM Initial Comments at 57-58; MISO Initial Comments at 16, 77; MISO TOs Reply Comments at 21-22; New York State Department Initial Comments at 10-11; NYISO Initial Comments at 33; SoCal Edison Initial Comments at 19.

delay penalties not attributable to an RTO/ISO transmission owning member.[1926] As an initial matter, we believe that any such burden is outweighed by the need to create an incentive to ensure that transmission providers timely complete interconnection studies. Also, we find that RTOs/ISOs do not face differing or greater burdens that warrant different treatment than non-RTO/ISO transmission providers. The *pro forma* LGIP applies to all transmission providers, RTO/ISO and non-RTO/ISO alike. To the extent that RTOs/ISOs elect to create a tariff mechanism for recovering study delay penalties, rather than relying on individual filings, as noted above, the RTO/ISO may submit an FPA section 205 filing to propose such a default structure. Finally, where the transmission-owning members of an RTO/ISO perform interconnection studies, there is little-to-no "fact-finding" to be done to determine to which public utility to assign study delay penalties, as the transmission owner will be automatically assigned the penalty pursuant 18 CFR section 35.28(f)(1)(ii).

998. In response to concerns that RTOs/ISOs have no ability to pay study delay penalties without collecting them from another party,[1927] we note that RTOs/ISOs have

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[1926] ISO-NE Initial Comments at 36; ISO/RTO Council Initial Comments at 5-6; MISO Initial Comments at 15, 75.

[1927] Alliant Energy Initial Comments at 6-7; EEI Initial Comments 17; Indicated PJM TOs Initial Comments at 37; ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 13, 71; MISO TOs Reply Comments at 20; NARUC Initial Comments at 18; NEPOOL Initial Comments at 16; NESCOE Reply Comments at 11; New York State Department Initial Comments at 10; North Dakota Commission Initial Comments at 6; NYISO Initial Comments at 32; Omaha Public Power Initial Comments at 11; OMS Initial Comments at 15; R Street Initial Comments at 14; State Agencies Initial Comments at 12-13; TAPS Initial Comments at 3-5; WIRES Initial Comments at 11.

several options under this final rule for collecting study delay penalties. As discussed above, RTOs/ISOs may submit FPA section 205 filings to seek recovery for study delay penalties from public utilities contributing to study delays. The FPA section 205 filing could propose either to establish a tariff mechanism for assigning costs generally or for assigning costs for specific study delay penalties. RTOs/ISOs also have other ways to fund study delay penalties beyond the revenue they collect for sales of transmission service: for example, RTOs/ISOs collect administrative fees from market participants.[1928]

999. We disagree with NYISO that study delay penalties would threaten the financial viability of RTOs/ISOs or fail to incentivize RTOs/ISOs to complete studies by the required deadlines. The evidence in this record does not demonstrate that the study delay penalty structure that we adopt in this final rule, combined with the multiple adopted safeguards, including a total cap on study delay penalty amounts, would threaten the financial viability of an RTO/ISO, particularly given that RTOs/ISOs may submit FPA section 205 filings to recover study delay penalties. Additionally, as noted, we find that it

[1928] For example, MISO recovers the costs of providing financial transmission rights (FTR) administrative service from FTR holders under its Rate Schedule 16 (MISO Tariff, Schedule 16). SPP recovers the costs of administering its transmission administration service, transmission congestion rights administrative service, and integrated marketplace clearing administrative service from transmission customers and market participants under its Rate Schedule 1-A (SPP Tariff, Schedule 1-A). PJM recovers the costs of its control area administration service, which includes "preserving the reliability of the PJM Region and administering Point-to-Point Transmission Service and Network Integration Transmission Service" from users of the service under Schedule 9-1 (PJM Tariff, Schedule 9-1).

is appropriate to incentivize RTOs/ISOs to meet study deadlines in the same manner as non-RTO/ISO transmission providers. Thus, we also disagree with NYISO that the study delay penalties for RTOs/ISOs should be smaller in size and slower to trigger.[1929] As discussed above, we believe that the study delay penalty structure strikes a reasonable balance by providing an adequate incentive without being punitive.

1000. AEP and TAPS assert that the imposition of study delay penalties will disincentivize RTO/ISO participation.[1930] We are not persuaded that any such disincentive outweighs the benefits of adopting study delay penalties. We expect that an incentive for transmission providers to meet interconnection study deadlines will result in more efficient interconnection queue processing, which will benefit competition and, in the long run, customers within a transmission provider's region, including within RTO/ISO regions. We continue to believe that customers are more likely to experience lower overall costs if the industry relies on robust wholesale competition to determine the appropriate level of generation and related transmission development.[1931]

1001. We find that applying study delay penalties to RTOs/ISOs for failing to meet interconnection study deadlines is consistent with Commission precedent and continues to be appropriate, particularly given the extent of interconnection queue backlogs in RTOs/ISOs. We disagree with NYISO that, because RTOs/ISOs may be at greater risk

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[1929] NYISO Initial Comments at 32, 37, 41.

[1930] AEP Initial Comments at 27-28; TAPS Initial Comments at 6.

[1931] *See* Order No. 2003-A, 106 FERC ¶ 61,220 at P 507.

of being assessed study delay penalties than reliability penalties, this meaningfully distinguishes study delay penalties from the Commission's findings in Order Nos. 672-A and 890 related to reliability penalties.[1932] In response to NYISO's comment that reliability penalties receive the Commission's close scrutiny, we note that transmission providers will have an opportunity to seek relief from a penalty by filing an appeal, which the Commission will closely scrutinize and in response to which the Commission will issue an order.[1933]

xi. Posting Requirements

1002. For transparency purposes, we adopt the proposed requirements in *pro forma* LGIP section 3.9(7) that transmission providers must post on their OASIS or other publicly accessible website on a quarterly basis, within 30 calendar days of the end of the calendar quarter, (1) the total amount of study delay penalties from the previous reporting quarter, and (2) the highest amount of such study delay penalties repaid to a single interconnection customer during the previous reporting quarter. We also adopt the proposed requirements in *pro forma* LGIP section 3.9(7) that transmission providers must maintain the quarterly measures posted on their OASIS or website for three calendar

[1932] Order No. 672-A, 114 FERC ¶ 61,328 at P 56 ("it is not arbitrary and capricious to treat all operators alike, including RTOs and ISOs, in terms of their liability for violation of a Reliability Standard."); Order No. 890, 118 FERC ¶ 61,119 at P 1357 ("we believe that all entities administering the tariff should operate under the same rules, reporting obligations, and performance metrics . . . Non-profit transmission providers have other sources of money to pay penalties beyond the revenue they collect for sales of transmission service.").

[1933] NYISO Initial Comments at 33-34.

years, with the first required posting to be the third cluster study cycle (including any transitional cluster study cycle, but not transitional serial studies) after the transmission provider transitions to the cluster study process. We believe that this additional information will be helpful to the public and the Commission in tracking the status of interconnection queue delays and that the burden on transmission providers of posting this information will be minimal.

xii. Force Majeure Exception

1003. We decline to adopt the NOPR proposal to exempt transmission providers from study delay penalties where *force majeure* applies. We believe that this exemption is unwarranted: transmission providers may explain in any appeal to the Commission any circumstances that caused the delay, including any events that qualify as *force majeure*, and the Commission will consider such circumstances as part of its evaluation of whether good cause exists to grant relief from the otherwise applicable study delay penalties.

xiii. Transmission Provider Resources

1004. In response to commenters that raise concerns about transmission provider resources to complete studies on time, we first emphasize that the overall set of reforms in this final rule should significantly streamline and reduce the number of interconnection studies that a transmission provider must conduct, easing the burden on transmission providers. With the benefit of fewer studies and fewer speculative generating facilities in the interconnection queue, we expect that a transmission provider that faces the potential of a study delay penalty for failing to meet interconnection study deadlines will be able to allocate sufficient resources to conduct interconnection studies, in addition to

implementing reforms to ensure that its study process is efficient. In this final rule, we adopt interconnection study deadlines for a transmission provider to complete cluster studies, cluster restudies, facilities studies, and affected system studies. As discussed above, we believe that the interconnection study deadlines will give transmission providers sufficient time to conduct the relevant studies, e.g., 150 calendar days for the completion of the cluster study, and we have demonstrated that the existing *pro forma* generator interconnection procedures and agreements are insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.[1934] We therefore believe that the record supports the imposition of study delay penalties for failure to meet those deadlines.

1005. Some commenters argue that other NOPR proposals, such as the optional resource solicitation studies, optional informational interconnection studies, and evaluation of advanced transmission technologies, will consume transmission provider resources otherwise dedicated to interconnection studies.[1935] Similarly, other commenters argue that imposing firm study deadlines will force transmission providers to redirect resources and personnel away from other necessary functions such as transmission planning or deprive them of financial resources and make it harder to retain qualified personnel.[1936]

[1934] *See supra* Section II.C.

[1935] Indicated PJM TOs Initial Comments at 36; MISO Reply Comments at 7; PPL Initial Comments at 24; SPP Initial Comments at 13.

[1936] Ameren Initial Comments at 21; Eversource Initial Comments at 25-26;

We note that we do not adopt the NOPR proposals to implement optional informational interconnection studies or optional resource solicitation studies and adopt a modified version of the NOPR proposal to require evaluation of certain enumerated advanced transmission technologies, which should reduce the burden on transmission providers as compared to that under the NOPR. Further, to these arguments, we note that it is the transmission provider's responsibility to manage its organizational resources—including attracting and retaining sufficient qualified personnel to meet its responsibilities—and that it is within the transmission provider's ability to improve how it manages its internal resources. If, for whatever reason, the transmission provider is not able to meet firm study deadlines, that is an issue the transmission provider is free to raise in appealing any penalties it incurs. While we are not persuaded that transmission providers will necessarily need to reassess their organizational needs to meet study deadlines, given the suite of reforms adopted in the final rule, to the extent that such steps are required, they are warranted to fulfill our responsibility under the FPA to ensure just and reasonable rates and to ensure that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner.

1006. We disagree with SoCal Edison and New York State Department that transmission providers will require additional resources to track and allocate study delay penalties,

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Indicated PJM TOs Initial Comments at 6, 24, 40; MISO TOs Initial Comments at 24; National Grid Initial Comments at 30; Pacific Northwest Utilities Initial Comments at 12; PJM Initial Comments at 57.

potentially increasing the cost of administering interconnection queues.[1937] We note that transmission providers already track the progress of their interconnection queues and should be aware of study deadlines, especially as their tariffs currently require reasonable efforts to meet such deadlines. As a result, determining when study delay penalties apply will be as straightforward as determining how many studies are late and past the 10-business day grace period from the applicable study deadline. As explained above, we anticipate that other provisions of this final rule will result in improved interconnection queue management and processing, which should ease the burden on transmission providers over time.

1007. We also disagree with commenters that firm study deadlines with study delay penalties will necessarily reduce interconnection study flexibility[1938] and accuracy,[1939] as

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[1937] New York State Department Initial Comments at 10-11; SoCal Edison Initial Comments at 19.

[1938] Dominion Reply Comments at 21; EEI Initial Comments at 15; Eversource Initial Comments at 25-26; NYISO Initial Comments at 38-39; WIRES Initial Comments at 10.

[1939] AECI Initial Comments at 6; Alliant Energy Initial Comments at 6; Avangrid Initial Comments at 9-10, 30; Bonneville Initial Comments at 15-16; CESA Reply Comments at 8; Clean Energy Buyers Initial Comments at 10-11; Enel Initial Comments at 48; Indicated PJM TOs Reply Comments at 26; ISO/RTO Council Initial Comments at 8; Longroad Energy Reply Comments at 14; MISO Initial Comments at 13, 71, 77-78; MISO TOs Initial Comments at 14, 24; National Grid Initial Comments at 30; NESCOE Reply Comments at 13; NextEra Reply Comments at 11; NYTOs Initial Comments at 24-28; North Dakota Commission Initial Comments at 6; NRECA Initial Comments at 34; NYISO Initial Comments at 38-39; Omaha Public Power Initial Comments at 12; OMS Initial Comments at 15; Ørsted Initial Comments at 15; PacifiCorp Reply Comments at 6; PJM Initial Comments at 8, 56-57; PPL Initial Comments at 19; SPP Initial Comments at 11-12; Tri-State Initial Comments at 18; Xcel Initial Comments at 38.

well as system reliability.[1940] We reiterate that it is within transmission providers' ability to improve interconnection study processes and policies and take other measures, such as hiring additional staff, to efficiently process interconnection queues without sacrificing accuracy, flexibility, or reliability. Study delay penalties will incentivize these actions, especially given transmission providers' independent responsibilities to deliver accurate studies and to ensure system reliability. Thus, we agree with the New Jersey Commission that there is not an inherent tradeoff between holding transmission providers accountable and transmission system reliability. In addition, we further agree that the failure to bring new generating facilities online in a timely manner can also create reliability and economic risk.[1941] Moreover, interconnection customers, rather than transmission providers, ultimately bear the costs of interconnection studies. To the extent that it is more costly to complete studies in a timely and accurate fashion, these interconnection study costs will be passed on to interconnection customers. Further, as noted above, the study delay penalty structure includes significant safeguards for the transmission provider, such as the transition period, the 10-business day grace period, the penalty cap, the ability to extend deadlines by mutual agreement, and the ability to appeal any study delay penalties to the Commission.

[1940] AEP Initial Comments at 28; Dominion Reply Comments at 21; MISO TOs Reply Comments at 18-19; NYISO Initial Comments at 39; PJM Initial Comments at 8, 56-57.

[1941] New Jersey Commission Reply Comments at 3.

xiv. Coordination Among Transmission Providers, Interconnection Customers, and Affected Systems

1008. Several commenters raise concerns related to affected systems, and coordination among transmission providers, interconnection customers, and affected systems. In response to NARUC's request for clarification regarding affected system studies, we note that new *pro forma* LGIP section 3.9 will apply to all transmission providers when they are acting as an affected system operator (affected system transmission providers).[1942] As a result, affected system transmission providers are also subject to a study delay penalty for a late affected system study. Thus, contrary to commenters' arguments that the NOPR proposal ignores that other entities, such as affected systems, may be responsible for study delays,[1943] affected system transmission providers will face the same incentive as the host transmission provider to timely complete their studies. In addition, where a delay for a host transmission provider's cluster or facilities studies is caused by affected system study delays, the host transmission provider can file an appeal of any applicable study delay penalty with the Commission and include such details in its claim of good cause for relief.

1009. We disagree with commenters' concerns that the study delay penalty structure would decrease or harm coordination between transmission providers, interconnection customers, and affected systems,[1944] and/or create tension between RTOs/ISOs,

[1942] NARUC Initial Comments at 14, 17.

[1943] ISO/RTO Council Initial Comments at 3-4; MISO Initial Comments at 74.

[1944] Alliant Energy Initial Comments at 6; EEI Initial Comments at 15; Eversource

transmission owners, developers, or other parties.[1945] The incentive for transmission providers to timely complete interconnection studies created by the study delay penalty structure should improve coordination among transmission providers and interconnection customers to ensure that transmission providers have the information needed to complete the studies and, if there is an issue, to pursue a potential extension of the deadline via mutual agreement. We note that other reforms adopted in this final rule will improve clarity and efficiency around affected system studies, which should improve coordination with affected systems. In addition, affected system transmission providers are also subject to study delay penalties for delayed affected system studies, which should encourage better coordination. We also believe that an ability to appeal study delay penalties will provide a structured forum for parties to dispute claims, placing the Commission in the position of decisionmaker when it comes to determining whether to excuse study delay penalties.

1010. We disagree with AECI that there is no benefit to imposing penalties on affected system transmission providers for failure to timely complete affected system studies. These studies equally affect interconnection customer certainty and interconnection process efficiency, and as such, we believe that the penalty structure enumerated above

Initial Comments at 25-26; MISO Reply Comments at 21; North Dakota Commission Initial Comments at 6.

[1945] AEP Initial Comments at 27; Dominion Initial Comments at 35-36; Indicated PJM TOs Reply Comments at 6-7, 27; NextEra Initial Comments at 30; NYISO Initial Comments at 39-40; PJM Initial Comments at 57-58.

will also incentivize transmission providers to complete affected system studies in a timely manner. Indeed, the Commission has addressed several instances where affected system studies have delayed or otherwise affected interconnection study timelines and processes,[1946] and therefore, without imposing a penalty structure, we are not convinced that transmission providers will timely complete their affected system studies. In the same vein, we agree with Interwest that monetary penalties for failure to meet the affected system study deadline will incentivize discipline and support investment needed to meet affected system study timelines.

1011. In response to ENGIE, MISO, and Duke Southeast Utilities' comments on the distribution of study delay penalties for failure to timely complete affected system studies, we note that any study delay penalties will be distributed on a pro rata basis per interconnection request to the affected system interconnection customers included in the relevant study that did not withdraw, or were not deemed withdrawn, from the interconnection queue before the missed study deadline.

xv. Commission Authority and Precedent

1012. Some commenters argue that the proposed study delay penalty structure is an unjustified shift from precedent established in Order No. 845, in which the Commission expressly declined to impose penalties.[1947] We disagree. As we explain above,

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[1946] *See, e.g.*, *Tenaska Clear Creek Wind, LLC v. Sw. Power Pool, Inc.*, 177 FERC ¶ 61,200 (2021); *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, 168 FERC ¶ 61,173 (2019).

[1947] MISO TOs Initial Comments at 21-22; NYISO Initial Comments at 26; PG&E

interconnection queue delays in many parts of the country have worsened since Order No. 845, and the record indicates that the failure of transmission providers to timely complete studies is a significant part of the reason why. For example, in the single year between 2021 and 2022, there was marked increase in the average length of time customers have been waiting in the interconnection queue, increasing from roughly 4 to 5 years, while at the same time seeing the total interconnection queue size increased from 1,400 GW to more than 2,000 GW.[1948] Based on the recent interconnection study metrics transmission providers posted in compliance with Order No. 845, of the 2,179 interconnection studies completed in 2022, 68% were issued late.[1949] Furthermore, at the end of 2022, an additional 2,544 studies were delayed (i.e., ongoing and past their deadline).[1950] All of the RTOs/ISOs except CAISO and 14 non-RTO/ISO transmission providers reported delayed studies at the end of 2022.[1951] We believe that this large number of delayed studies is a significant part of the explanation for the extensive delays and growing interconnection queues documented above and in the Overall Need for

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Initial Comments at 6; PG&E Reply Comments at 3.

[1948] Queued Up 2022 at 3; Queued Up 2023 at 3, 31.

[1949] Based on data provided by transmission providers in compliance with Order No. 845. *See* Appendix B to this final rule for the underlying data.

[1950] *Id.* Note that the vast majority of these studies (2,211) were in PJM.

[1951] *Id.* CAISO revised the interconnection study deadlines of their queue cluster 14 to account for the unprecedented increase in interconnection requests. *Cal. Indep. Sys. Operator Corp.*, 176 FERC ¶ 61,207.

Reform Section. Accordingly, based on the evidence in *this* record, we find that study delay penalties are an appropriate component of a just, reasonable, and not unduly discriminatory or preferential replacement rate to remedy these interconnection delays and the consequences they have for Commission-jurisdictional rates.[1952]

1013. Similarly, in response to commenters who argue that the proposed study delay penalty structure differs from the penalty structure implemented in Order No. 890 for transmission service studies,[1953] we believe that such differences are warranted by the significant and growing interconnection queue backlogs. We agree with PacifiCorp that, compared to transmission service requests, interconnection studies are more numerous, complex, and susceptible to delays.[1954] Further, as noted above, there is a growing number of interconnection customers affected by study delays. We believe that these factors underscore the need for transmission providers to meet study deadlines and the need to provide an incentive, in the form of study delay penalties. We find that the other reforms adopted in this final rule will streamline interconnection processes: for example, the cluster study process will reduce the number of interconnection studies that any transmission provider must conduct at a given time, thus reducing the potential for study

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[1952] *See Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 56-57 ("[T]he agency is entitled to change its view . . . [if it] explain[s] its reasons for doing so.").

[1953] Eversource Initial Comments at 30; MISO Reply Comments at 21; MISO TOs Initial Comments at 19-21; PacifiCorp Initial Comments at 33-34; Tri-State Initial Comments at 18.

[1954] PacifiCorp Initial Comments at 33-34.

delay penalties to accumulate relative to the serial study process in place today. We find that the elimination of the reasonable efforts standard and adoption of the study delay penalty structure will incentivize transmission providers to take appropriate steps to meet the study deadlines in their tariffs.

1014. We also disagree with TAPS' assertion that reliability penalties are permissible because they are part of a congressionally mandated regime, whereas the study delay penalties are not.[1955] We find that FPA section 206 provides us with the authority to establish a structure to impose study delay penalties because such delays render Commission-jurisdictional rates unjust and unreasonable, as explained in the Overall Need for Reform Section, and we believe that this structure reflects a just and reasonable replacement rate.[1956] As discussed above, an RTO/ISO has different options for recovering those penalties, and we are not in this final rule dictating which option an RTO/ISO must choose. Further, TAPS' argument that reliability penalties are used to offset NERC's operation costs but the interconnection study delay penalties will not be used to offset costs for consumers or ratepayers does not change our conclusion.[1957] We do not believe that our authority to require study delay penalties as part of a just and reasonable replacement rate turns on the entity whose costs are offset by the penalties collected, and as discussed above, we find it appropriate in this circumstance to use study

[1955] TAPS Initial Comments at 5 (citing 16 U.S.C. 824o).

[1956] 16 U.S.C. sec. 824e.

[1957] TAPS Initial Comments at 5.

penalties to offset the interconnection study costs for interconnection customers that are affected by the study delays.

1015. Moreover, automatic tariff-based penalty mechanisms similar to that which we adopt in this final rule exist in a variety of other contexts. For example, RTO/ISO tariffs include penalties for "traffic ticket" violations that are penalized without referral to the Commission.[1958] In that context, the Commission has approved such automatic penalties where (1) the activity is expressly set forth in the tariff, (2) the activity involves objectively identifiable behavior, and (3) the activity does not subject the actor to sanctions or consequences other than those expressly approved by the Commission and set forth in the tariff, with the ability to appeal[1959] to the Commission.[1960] That is the same structure we are adopting here: the study delay penalties (1) will be expressly set forth in the tariff, (2) will be based on objectively identifiable behavior (i.e., whether a study is late), and (3) will only trigger consequences expressly approved by the

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[1958] *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,050, at PP 34-35 (2011); *N.Y. Indep. Sys. Operator*, *Inc.*, 131 FERC ¶ 61,225, at P 16 (2010). Also, in Order No. 890, the Commission approved other tariff-based "operational penalties" on customers where it similarly did not require notification or review by the Commission of the assessed penalty. *See* Order No. 890, 118 FERC ¶ 61,119 at PP 834-36.

[1959] *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 175 FERC ¶ 61,043 (2021) (excusing penalties for late meter data revisions); *Lathrop Irrigation Dist.*, 161 FERC ¶ 61,243 (2017) (denying request for waiver of CAISO tariff provisions that impose penalties on late submission by LSEs of required information for resource adequacy plans).

[1960] *Cal. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,050 at PP 34-35.

Commission (i.e., the $1,000/$2,000/$2,500 per business day penalties with the ability to appeal to the Commission.

1016. In response to Indicated PJM TOs' argument that the Commission lacks the authority to require RTOs/ISOs to seek cost recovery of study delay penalties from transmission owners within the RTO/ISO,[1961] we note that this concern is moot because we are declining to adopt the NOPR proposal to require RTOs/ISOs to submit requests to recover the costs of specific study delay penalties. Further, we modify our proposal to adopt revisions to 18 CFR section 35.28(f)(1)(ii) to automatically apply study delay penalties to transmission owners within RTOs/ISOs when those transmission owners have conducted the delayed studies. Finally, as discussed above, RTOs/ISOs *may* submit an FPA section 205 filing to propose a default structure for recovering study delay penalties or make individual FPA section 205 filings to recover the costs of any specific study delay penalties.

xvi. <u>Miscellaneous</u>

1017. We also decline to adopt alternative proposals for study delay penalty structures. We find the penalty structure that we adopt in this final rule to be a just and reasonable replacement rate, which is all that the Commission is required to show under FPA section 206.[1962]

[1961] Indicated PJM TOs Initial Comments at 44-45.

[1962] *Entergy Ark., LLC v. FERC*, 40 F.4th 689, 701 (D.C. Cir. 2022) (explaining that in setting the replacement rate under FPA section 206, "FERC is not required to choose the best solution, only a reasonable one") (quoting *Petal Gas Storage*, *LLC v.*

1018. In response to EEI's and Eversource's comments concerning why the good utility practice standard, which is contained within the text of the definition of the reasonable efforts standard in the *pro forma* LGIP, would no longer apply to interconnection processes,[1963] we clarify that the elimination of the reasonable efforts standard does not eliminate the requirement that transmission providers act consistent with good utility practice when conducting interconnection studies. Therefore, we adopt revisions to section 4.2 of the *pro forma* LGIP to indicate that transmission providers must continue to conduct interconnection studies consistent with good utility practice.

1019. Some commenters argue that interconnection study deadlines should be extended in cases of interconnection customer-caused delays and that the timeline for completing such studies should not restart until after an interconnection customer submits all necessary information and cures any deficiencies; they also argue that transmission providers should not be penalized if study delays are caused by a higher-queued cluster being restudied.[1964] We decline to adopt these modifications. As an initial matter, we note that if an interconnection customer fails to adhere to all requirements in the *pro forma* LGIP, except in the case of disputes, the transmission provider shall deem the interconnection customer's interconnection request to be withdrawn pursuant to section

FERC, 496 F.3d 695, 703 (D.C. Cir. 2007)).

[1963] EEI Initial Comments at 15; Eversource Initial Comments at 22-24.

[1964] APPA-LPPC Initial Comments at 21; NRECA Initial Comments at 34; Tri-State Initial Comments at 18-19.

3.7 of the *pro forma* LGIP. To the extent that study delays result from an interconnection customer's actions or higher-queued cluster restudies, transmission providers may record the length of those delays and report that information in any appeal of study delay penalties filed with the Commission.

1020. We disagree with PJM that interconnection customers will be incentivized to delay studies of their interconnection requests in order to offset their study costs via study delay penalties being allocated to them from the transmission provider.[1965] We agree with AEE that the economic harms of delaying the interconnection process for an interconnection customer with a commercially viable interconnection request, especially given the reforms adopted in this final rule (e.g., increased study deposits, commercial readiness deposits, and withdrawal penalties) significantly outweigh any economic incentive for interconnection customers to delay the interconnection process in hopes of a study delay penalty to offset study costs.[1966] For example, a cluster study delayed by 100 business days would generate $100,000 in study delay penalties to be distributed among all interconnection customers in the cluster, yet such a lengthy delay could force an interconnection customer to withdraw from the interconnection queue due to commercial obligations and carries an interconnection customer withdrawal penalty risk of two times the study cost.

[1965] PJM Initial Comments at 57.

[1966] AEE Reply Comments at 35-36.

1021. We decline requests to delay implementation of the study delay penalty reforms until other reforms in this rulemaking and related rulemakings, such as those in Docket No. RM22-17, take effect.[1967] As explained above, our modification to the NOPR's proposed transition mechanism for study delay penalties, which will allow transmission providers to complete two cluster study cycles before being subject to study delay penalties, will provide sufficient time for transmission providers to implement the other reforms adopted in this final rule. This transition mechanism will also give transmission providers currently undergoing their own interconnection queue reform efforts, as SPP and NYISO explain they are, time to implement those reforms.[1968] In addition, we find that the study delay penalties are just and reasonable based on the record in this proceeding and that it would not be appropriate to delay their effect until action is taken in other proceedings. To the extent the Commission finalizes the proposed reforms in separate proceedings, the Commission will consider how to address potential interactions between the reforms adopted in this final rule and elsewhere.

[1967] AEP Initial Comments at 29; Avangrid Reply Comments at 14; Clean Energy Buyers Initial Comments at 10-11; Eversource Initial Comments at 30-31; Idaho Power Initial Comments at 10; ISO/RTO Council Reply Comments at 5; Longroad Energy Reply Comments at 15; NY Commission and NYSERDA Initial Comments at 6; NYISO Initial Comments at 30; Pacific Northwest Utilities Initial Comments at 9-10; PacifiCorp Initial Comments at 34; Puget Sound Initial Comments at 11; State Agencies Initial Comments at 14; TAPS Initial Comments at 9.

[1968] NYISO Initial Comments at 30; SPP Initial Comments at 14-15.

1022. In response to WAPA's comment that federal agencies should not be subject to study delay penalties absent a specific Congressional waiver of sovereign immunity,[1969] we clarify that the penalties will apply to the extent that a non-public utility has adopted the proposed penalty provisions as a part of its reciprocity tariff.[1970] Under the safe harbor procedure set out in Order No. 888, non-public utilities may voluntarily submit to the Commission an open access transmission tariff; if the Commission finds that the tariff contains terms and conditions that substantially conform or are superior to those in the *pro forma* open access transmission tariff, the Commission will deem it an acceptable reciprocity tariff and will require public utilities to provide open access transmission service to that particular non-public utility (safe harbor treatment).[1971] We find that, where such non-public utilities voluntarily file a reciprocity tariff, they consent to abide by the Commission's open access principles and the various provisions of the *pro forma* tariff, which would include the penalties we are adopting in this final rule (unless the

[1969] WAPA Initial Comments at 10.

[1970] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission on Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,760-763 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002).

[1971] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,761.

Commission were to find that a safe harbor tariff without those penalty provisions substantially conforms or is superior to the *pro forma* tariff).[1972]

1023. WAPA cites to *Southwestern Power Admin. v. FERC*[1973] for its proposition that, absent a specific waiver of sovereign immunity, federal agencies are not subject to monetary penalties.[1974] We find that case inapposite because the penalties adopted here are not civil monetary penalties imposed by the Commission and paid to the U.S. Treasury. Instead, they would be penalties imposed pursuant to a voluntarily submitted reciprocity tariff and would be distributed to the delayed interconnection customer(s) in the relevant study that remained in the interconnection queue at the time the penalty would be distributed. WAPA and other federal agencies, if they file reciprocity tariffs, would voluntarily choose to abide by the terms of those tariffs and thus would consent to any penalty structures contained in them.

1024. We decline to adopt commenters' suggestions to create generic exceptions to study delay penalties.[1975] Not only do we lack record support for some of the

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[1972] Where, as here, the Commission makes changes to the *pro forma* tariff, a non-public utility that already has a reciprocity tariff and wishes to maintain its safe harbor treatment must amend its tariff so that its provisions substantially conform or are superior to the revised *pro forma* tariff. *See* Order No. 2003, 104 FERC ¶ 61,103 at P 842.

[1973] *Sw. Power Admin. v. FERC*, 763 F.3d 27 (D.C. Cir. 2014).

[1974] WAPA Initial Comments at 10 n.12.

[1975] Indicated PJM TOs Initial Comments at 42; MISO TOs Initial Comments at 25; National Grid Initial Comments at 32; NESCOE Initial Comments at 16; NYISO Initial Comments at 42; PPL Initial Comments at 19; SoCal Edison Initial Comments at 19; Tri-State Initial Comments at 18; WIRES Initial Comments at 10; Xcel Initial

suggestions, but we also believe that transmission provider requests for an exception to a study delay penalty are best addressed on a case-by-case basis via the appeal process outlined above.

1025. We decline to adopt alternative proposals suggested by various commenters. For example, we do not believe that imposing only a reporting requirement on study delays is sufficient to resolve the problem of interconnection queue backlogs and repeatedly delayed interconnection studies. Similarly, we decline to condition study delay penalties on the outcome of a show cause proceeding conducted by the Commission, as suggested by MISO,[1976] because it would be administratively burdensome and may not create a sufficient incentive for transmission providers to meet interconnection study deadlines. We also decline to adopt suggestions such as creation of favorable rate treatment for transmission providers that meet interconnection study deadlines[1977] or tying interconnection study performance to executive compensation,[1978] which we do not believe would ensure that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner as effectively as the study delay penalty structure that we adopt instead.

Comments at 38.

[1976] MISO Initial Comments at 79-80.

[1977] Longroad Energy Reply Comments at 14-15; Shell Initial Comments at 11.

[1978] Clean Energy States Initial Comments at 10-11; CREA and NewSun Reply Comments at 57; TAPS Initial Comments at 8.

2. Affected Systems

a. Need for Reform

i. NOPR Proposal

1026. In the NOPR, the Commission preliminarily found that the affected system study process lacks consistency between transmission providers.[1979] The Commission stated that, without any requirement for a timely cost determination, affected system operators may not return study results in time for interconnection customers to make informed decisions to facilitate interconnection of their generating facilities. The Commission added that, due to this lack of information, there may continue to be late-stage withdrawals resulting from unexpected high costs for affected system network upgrades that create restudies and delays.[1980] The Commission also noted that interconnection customers recommended standardization of the affected system study process in both the technical conference in Docket No. AD18-8-000 and in comments on the ANOPR in Docket No. RM21-17-000, specifically asking for standardization of the timing of study

[1979] NOPR, 179 FERC ¶ 61,104 at P 179 (citing May Joint Task Force Tr. 67:6-8 (Dan Scripps) ("Specifically, there may be an opportunity to create a general framework that would be consistent across RTO seams."); *id.* 68:12-18 (Ted Thomas) (agreeing with Chair Scripps that "the most effective place that FERC can operate is in the area where you have two RTOs and the real issue is getting them on the same page")).

[1980] *Id.* (citing May Joint Task Force Tr. 67:14-17 (Dan Scripps) ("[W]e expect the affected systems study process to become increasingly critical as more renewable resources come online in renewable rich areas and transmission capacity becomes ever more scarce.")).

results, the amount of study costs, and modeling criteria used in affected system studies.[1981]

1027. The Commission noted that, currently, detailed information about any two transmission providers' affected system study processes is found in multiple transmission provider documents and is not necessarily cohesive, which appears to create confusion and uncertainty.[1982] The Commission further preliminarily found that, despite these documents, much of the affected system study process is ad hoc and, therefore, unclear to interconnection customers. In addition, the Commission explained that affected system study processes are highly variable based on region and transmission provider, and they may not be uniform even across a single transmission provider's footprint.

1028. The Commission preliminarily found that the lack of an affected system study process results in Commission-jurisdictional rates that are unjust and unreasonable because an interconnection customer cannot evaluate its costs in a timely manner, which increases uncertainty and may result in late-stage withdrawals and subsequent restudies, delays, and increased costs to the remaining interconnection customers in the interconnection queue.[1983] The Commission stated that, without a transparent affected

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[1981] *Id.* P 180 (referencing May Joint Task Force Tr. 64:18-24 (Dan Scripps) (stating that "FERC may have a larger role to play in issues that cross RTO boundaries, particularly, around cross-RTO affected system studies where individual RTOs have limited control" and certainty "around the timing of affected systems studies")).

[1982] *Id.* P 181.

[1983] *Id.* P 182.

system study process, it appears that neither an interconnection customer nor the Commission can evaluate whether the affected system operator has acted in an unduly discriminatory manner. The Commission further stated that reforms to improve transparency and coordination, therefore, may be necessary to establish a just, reasonable, and not unduly discriminatory or preferential affected system study process.

ii. Comments

1029. Multiple commenters generally support action to address the Commission's identified need to reform affected system study processes.[1984] For example, AEE asserts that existing affected system study processes are plagued by uncertainty and a lack of transparency, which, in turn, create delays, interconnection queue withdrawals, and cost increases.[1985] Invenergy, Enel, and SEIA assert that current misalignments in and lack of coordination of affected system study processes can lead to uncertain, duplicative, or unexpected study results.[1986] Some commenters support synchronization and harmonization of affected system study processes, with NextEra alleging that study

[1984] ACE-NY Initial Comments at 8-9; AEE Initial Comments at 34-35; Enel Initial Comments at 58; Google Initial Comments at 5-6, 22; Invenergy Initial Comments at 40; Omaha Public Power Initial Comments at 12; SEIA Initial Comments at 34-35; Shell Initial Comments at 30.

[1985] AEE Initial Comments at 34-35; *see also* ELCON Initial Comments at 7; SEIA Initial Comments at 34-35; Shell Initial Comments at 30.

[1986] Enel Initial Comments at 58; Invenergy Initial Comments at 40; SEIA Initial Comments at 34-35. Invenergy states that many commenters acknowledge the need for improvements to current affected system study processes. Invenergy Reply Comments at 7-8.

processes across several regions lack transparency, consistency, coordination, and accountability, which results in errors and delays.[1987] Similarly, Google contends that current affected system study processes lack deadlines or structure, which exacerbates anticipating interconnection costs and, in turn, stifles investments.[1988] National Grid asserts that host transmission system and affected system study processes can be significantly misaligned with project development, investment, and financing timelines and decision points, resulting in unmanageable risk for interconnection customers.[1989]

1030. Several commenters highlight the shortcomings of current *pro forma* LGIP requirements and their contribution to affected system study process problems.[1990] ACE-NY emphasizes that nothing in the *pro forma* LGIP binds the affected system study process, and, as a result, interconnection customers are open to significant impacts and unreasonable timelines.[1991] OMS highlights the limited control that RTOs/ISOs have regarding the timing of affected system studies.[1992] NYISO and Ameren assert that more

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[1987] APS Initial Comments at 19; ELCON Initial Comments at 7; NextEra Initial Comments at 31-32; NextEra Reply Comments at 4; Omaha Public Power Initial Comments at 12.

[1988] Google Initial Comments at 5-6, 22; U.S. Chamber of Commerce Initial Comments at 10-11.

[1989] National Grid Initial Comments at 35.

[1990] *See, e.g.*, Clean Energy Associations Initial Comments at 47-48; UMPA Initial Comments at 5-6.

[1991] ACE-NY Initial Comments at 9.

[1992] OMS Initial Comments at 16; *see also* PJM Reply Comments at 10 (arguing that an RTO/ISO has no authority to compel other RTOs/ISOs to complete

specific requirements regarding roles and responsibilities of parties in the affected system study process are needed.[1993] According to Invenergy, the Commission has until now declined to impose any organized structure around the affected system study process because affected system network upgrades and associated costs were thought to be a relatively rare occurrence.[1994] Invenergy contends that this has resulted in transmission providers conducting studies using variable study assumptions and standards and assigning significant system upgrade costs at any time, even after an interconnecting generating facility is already in operation.

1031. On the other hand, several commenters doubt whether standardization of affected system study processes is warranted and argue that adopting the NOPR proposal will cause timeline problems and delays.[1995] SDG&E contends that, based on its experience, affected system studies infrequently trigger the need for construction of new network upgrades, and thus it does not find the current process deficient.[1996] AECI states that its current coordination process is not in need of reform because it effectively coordinates

interconnection studies on its deadline).

[1993] Ameren Initial Comments at 22; NYISO Initial Comments at 44.

[1994] Invenergy Initial Comments at 39 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 120).

[1995] Dominion Initial Comments at 36-37; PJM Initial Comments at 63; SPP Initial Comments at 17; WAPA Initial Comments at 10.

[1996] SDG&E Reply Comments at 3.

with several affected systems and recognizes the unique situations presented at different seams.[1997]

iii. Commission Determination

1032. We affirm the Commission's preliminary findings in the NOPR that there is a compelling need for affected system study process reforms. The record demonstrates that, absent reforms, affected system studies will likely remain ad hoc, continuing to create and increase delays in the interconnection process, which leads to increased costs for both interconnection customers and consumers, thereby failing to ensure just and reasonable rates. As discussed by commenters, the existing affected system study processes lack certainty and transparency, which, in turn, create interconnection queue delays, interconnection customer withdrawals, and cost increases.[1998] Affected system study delays continue to be a major reason for interconnection queue delays.[1999] We concur with commenters that better coordination and more specific requirements concerning the role and responsibilities of affected system transmission providers are required to address the lack of certainty and transparency.[2000] Additionally, we agree with commenters that affected system study process reforms will ensure that

[1997] AECI Initial Comments at 6.

[1998] AEE Initial Comments at 34-35; ELCON Initial Comments at 7; SEIA Initial Comments at 34-35; Shell Initial Comments at 30.

[1999] *See* MISO, Informational Report Regarding Interconnection Study Delay for 4th Quarter 2022, Docket No. ER19-1960-004, attach. A at 8 (filed Feb. 14, 2023).

[2000] Ameren Initial Comments at 22; NYISO Initial Comments at 44.

interconnection customers are able to connect in a reliable, efficient, transparent, and timely manner.[2001] We are unpersuaded by comments that standardizing the affected system study process will result in timeline problems and delays;[2002] we find such claims to be speculative and contrary to the Commission's experience with standardizing host transmission provider study processes via the *pro forma* LGIP.[2003] We discuss specific aspects of the affected system-related NOPR proposals and final rule determinations below.

1033. In this final rule, an affected system transmission provider refers to a public utility transmission provider as the Commission does not have jurisdiction over the rates, terms, or conditions of service of non-public utility transmission providers. Thus, the requirements adopted in this final rule pertaining to affected system transmission providers are limited to public utility transmission providers.

b. Affected System Study Process

i. NOPR Proposal

1034. In the NOPR, the Commission proposed to revise the *pro forma* LGIP to include an affected system study process.[2004] The proposed process includes an initial

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[2001] MISO Initial Comments at 8 n.20, 12.

[2002] Dominion Initial Comments at 36-37; PJM Initial Comments at 63; SPP Initial Comments at 17; WAPA Initial Comments at 10.

[2003] *See* Order No. 2003, 104 FERC ¶ 61,103 at PP 10-12; Order No. 845, 163 FERC ¶ 61,043 at PP 4, 8, 39, 221, 239, 559.

[2004] NOPR, 179 FERC ¶ 61,194 at P 183.

notification, an affected system scoping meeting, a study process, the establishment of interconnection queue priority for the purposes of network upgrade cost allocation, the presentation of study results and an assessment of those results, and imposition of penalties if an affected system transmission provider fails to meet a study deadline. The Commission also proposed to add several definitions to the *pro forma* LGIP, including "affected system interconnection customer," "affected system network upgrade," "affected system scoping meeting," and "affected system study."

1035. The Commission proposed to require that the host transmission provider notify the affected system operator of a potential affected system impact caused by an interconnection request within 10 business days after the close of the first event giving rise to the identification of an affected system impact.[2005] The Commission explained that, for host transmission providers using a cluster study process, this event could be (1) the cluster request window, (2) the customer engagement window, (3) the cluster study, or (4) the cluster restudy as part of the first-ready, first-served cluster study process. At the same time that the host transmission provider notifies the affected system operator, the Commission proposed to require the host transmission provider to provide the interconnection customer with a list of potential affected systems, along with relevant contact information. The Commission also proposed to require the host transmission provider to provide the affected system operator with data on a monthly basis, or more

[2005] *Id.* P 184.

frequently as needed, about its transmission system and generation in its interconnection queue for the duration of the affected system study process.

1036. The Commission proposed several requirements on transmission providers acting as an affected system operator, whose transmission systems may be impacted by the proposed interconnection of a generating facility to a transmission system other than the transmission provider's transmission system.[2006] The Commission proposed to require the affected system transmission provider, within 15 business days of receiving notification from the host transmission provider of an impact on its transmission system, to respond in writing indicating whether it intends to perform an affected system study.

1037. The Commission proposed to require that the affected system transmission provider schedule an affected system scoping meeting within seven business days after providing written notification that it intends to conduct an affected system study.[2007] The Commission also proposed to require that the affected system scoping meeting be held within seven business days after it is scheduled. The Commission further proposed to require that the affected system transmission provider include the affected system interconnection customer in the scoping meeting and use best efforts to include the transmission provider with whom interconnection has been requested. The Commission proposed to require the affected system transmission provider to share the schedule to

[2006] *Id.* P 185.

[2007] *Id.* P 186.

complete the affected system study with all scoping meeting attendees within 15 business days after the close of the scoping meeting.

1038. The Commission proposed to require that the affected system transmission provider tender an affected system study agreement to the affected system interconnection customer within five business days of sharing the schedule for the affected system study.[2008] The Commission also proposed to require the affected system interconnection customer to return the executed affected system study agreement within 10 business days of receipt.

1039. The Commission proposed to require the affected system transmission provider to use what it referred to as a "first-ready, first-served interconnection queue priority approach," which would also determine how affected system network upgrade costs will be allocated by that transmission provider amongst interconnection customers in separate transmission systems.[2009] Specifically, the Commission explained, in some situations, both affected system interconnection customers and interconnection customers on the transmission system of the affected system transmission provider cause the need for affected system network upgrades; in this case, each interconnection customer's relative interconnection queue priority must be determined. The NOPR's proposed first-ready, first-served interconnection queue priority approach would require the affected system transmission provider to assign the affected system interconnection customer a queue

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[2008] *Id.* P 188.

[2009] *Id.* P 189.

position in its interconnection queue according to when the affected system interconnection customer executes an affected system study agreement, rather than when the affected system interconnection customer entered its host transmission provider's interconnection queue. The Commission explained that such a position would be equivalent to that of a transmission provider's own interconnection customer that had just received its cluster study report. The Commission also proposed to require the affected system transmission provider to allocate network upgrade costs among equally queued interconnection customers using a proportional impact method.

1040. The Commission proposed that the affected system transmission provider must provide the affected system interconnection customer with affected system study results within 90 calendar days after the receipt of the executed affected system study agreement.[2010] The Commission proposed to require that the affected system transmission provider include in the study results both the estimated costs for any network upgrades identified in the study and the timing for the construction of those network upgrades.

1041. The Commission proposed to require that the affected system transmission provider provide the affected system interconnection customer with an affected system facilities construction agreement within 30 calendar days after providing the affected system study results.[2011] The Commission proposed that the affected system

[2010] *Id.* P 190.

[2011] *Id.* P 191.

interconnection customer would then be required to notify the affected system transmission provider within five business days of executing the generator interconnection agreement with its host transmission provider whether it would like to execute the affected system facilities construction agreement or request that it be filed unexecuted with the Commission. The Commission proposed that the affected system transmission provider would then be required to execute, or file unexecuted, the affected system facilities construction agreement within five business days after receiving such direction from the affected system interconnection customer.

1042. The Commission proposed to impose financial penalties on affected system transmission providers that fail to timely complete affected system studies.[2012] The Commission explained that a host transmission provider would not be penalized for a late affected system study and did not require a host transmission provider to wait on the results of an affected system study to conduct its cluster study, so that any affected system study delay would not delay such a cluster study. The Commission clarified that the affected system transmission provider was the only entity that would be penalized for failure to timely complete an affected system study.

[2012] *Id.* P 192.

ii. Comments

(a) Comments in Support

1043. Multiple commenters support the NOPR proposal to create a standardized affected system study process in the *pro forma* LGIP.[2013] Consumers Energy asserts that standardization and better synchronization of timelines and processes between transmission providers will improve the interconnection process,[2014] and in ACORE's opinion, will help to prevent the use of potentially unjust, unreasonable, and unduly discriminatory or preferential ad hoc approaches.[2015]

1044. Multiple commenters support most or all of the proposed reforms.[2016] Pine Gate strongly supports the NOPR proposal's definitive deadlines for affected system study

[2013] ACE-NY Initial Comments at 8-9; AEE Initial Comments at 34-35; AEP Initial Comments at 31; AES Initial Comments at 21; APPA-LPPC Initial Comments at 23; CREA and NewSun Initial Comments at 86; Duke Southeast Utilities Initial Comments at 12; EDF Renewables Initial Comments at 10; ELCON Initial Comments at 7; Enel Initial Comments at 2, 57; ENGIE Initial Comments at 8; Fervo Energy Initial Comments at 6; Google Initial Comments at 5-6; Idaho Power Initial Comments at 11; NextEra Initial Comments at 31; Ohio Commission Consumer Advocate Initial Comments at 13; PacifiCorp Initial Comments at 36; Pattern Energy Initial Comments at 24; Pine Gate Initial Comments at 41; PPL Initial Comments at 19; SEIA Initial Comments at 34; Shell Initial Comments at 29.

[2014] Consumers Energy Initial Comments at 8; *see also* Clean Energy Associations Initial Comments at 47-48; Illinois Commission Initial Comments at 9; CREA and NewSun Initial Comments at 86-87; ENGIE Initial Comments at 8; U.S. Chamber of Commerce Initial Comments at 10-11.

[2015] ACORE Initial Comments at 4-5; *see also* EDF Renewables Initial Comments at 11; Invenergy Initial Comments at 41.

[2016] ACE-NY Initial Comments at 9; Google Initial Comments at 23; Pine Gate Initial Comments at 42.

completion and associated incentives, arguing that consistent, published criteria will help determine whether an affected system study is needed and will provide interconnection customers with the opportunity to conduct their own engineering analyses applying the criteria in order to better determine suitable locations for prospective generating facilities.[2017] AEP supports the deadlines related to initiating the affected system study process, stating that deadlines would help to provide transparency and ensure that the process is initiated in a timely fashion.[2018] Interwest, National Grid, and Invenergy support the proposal to standardize the affected system study engagement and participation process, asserting that the reforms are a significant improvement over the status quo.[2019]

(b) <u>Comments in Opposition</u>

1045. Multiple commenters oppose the NOPR's affected system study process proposal.[2020] Some commenters assert that the proposed process will impose arbitrary

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[2017] Pine Gate Initial Comments at 42-43; *see also* ENGIE Initial Comments at 9-10.

[2018] AEP Initial Comments at 31.

[2019] Interwest Reply Comments at 16-17; Invenergy Initial Comments at 40; National Grid Initial Comments at 35.

[2020] Dominion Initial Comments at 36-37; National Grid Initial Comments at 37; NextEra Initial Comments at 32; NextEra Reply Comments at 4; North Carolina Commission and Staff Initial Comments at 24; Pacific Northwest Utilities Initial Comments at 15; PJM Initial Comments at 63-64; SDG&E Reply Comments at 3; SPP Initial Comments at 17; WAPA Initial Comments at 10-11.

and strict deadlines and will be unworkable.[2021] Dominion and SDG&E assert that timing for affected system studies should not be standardized because the necessary study assumptions depend on timing of studies in the cluster study process.[2022] Dominion contends that, if an affected system study is performed too early, modeling assumptions may not yield meaningful results, resulting in incorrect cost estimates likely to cause restudies and late-stage withdrawals.[2023] PJM argues that studying affected system interconnection requests before all studies have been completed, or studying them for ERIS, could cause operational problems, require curtailment, or lead to late-stage withdrawals after the full scope of necessary network upgrades is known.[2024] Similarly, SPP states that, because the NOPR proposal does not prescribe any particular level of precision for the cost and timing estimates associated with affected system upgrades, the results received by the interconnection customer could lack sufficient detail and lead to higher-than-anticipated costs.[2025]

1046. Several commenters argue that certain elements of the NOPR proposal do not achieve the goal of increased efficiency.[2026] Recognizing that affected system studies

[2021] Dominion Initial Comments at 37; NextEra Initial Comments at 32; NextEra Reply Comments at 4; PJM Initial Comments at 63; SDG&E Reply Comments at 3.

[2022] Dominion Initial Comments at 36-37; SDG&E Reply Comments at 3.

[2023] Dominion Initial Comments at 37.

[2024] PJM Initial Comments at 64.

[2025] SPP Initial Comments at 17.

[2026] *Id.*; CAISO Initial Comments at 28; Dominion Initial Comments at 36-37;

require separate case preparations and a greater level of coordination between parties, SDG&E agrees with CAISO that the proposal has the potential to increase the number of affected system studies, with limited benefit.[2027] National Grid cautions that standardizing the affected system study process will necessitate host and affected system transmission providers to devote more resources to that process, which could cause delays.[2028] PJM contends that, although the NOPR proposal provides that transmission providers conducting cluster studies are not required to delay those studies by waiting for the results of affected system studies, such delays will be inevitable under the proposed process due to the additional steps and coordination required and the overlap in personnel and deadlines.[2029] PJM and National Grid both express concerns regarding the justness and reasonableness of the NOPR's penalty regime given the potential for additional delays in affected system studies.[2030]

1047. Other commenters argue that the NOPR proposal does not go far enough to improve efficiency in the affected system study process. North Carolina Commission and Staff call for more comprehensive reforms, recognizing the need for coordination

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National Grid Initial Comments at 37; PJM Initial Comments at 63; SDG&E Reply Comments at 3; WAPA Initial Comments at 10.

[2027] SDG&E Reply Comments at 3.

[2028] National Grid Initial Comments at 37.

[2029] PJM Initial Comments at 63.

[2030] *Id.*; National Grid Initial Comments at 37.

between transmission providers to avoid unnecessary expense and system disruption.[2031] WAPA recommends that the Commission consider an alternative strategy in which the host transmission provider includes contingencies and sensitivity scenarios involving potentially affected systems in its own studies.[2032] PJM suggests that, rather than the NOPR's "overly prescriptive" approach, the Commission should require a stated affected system coordination structure with defined steps and checkpoints, similar to the process PJM has been working to implement with neighboring systems through its joint operating agreements.[2033]

(c) <u>Comments on Specific Proposal</u>

(1) <u>Definitions</u>

1048. PPL argues that the proposed term "affected system interconnection customer" is confusing and recommends that the Commission either remove "interconnection" or consider the term "direct connect system customer," asserting that the affected system interconnection customers are not interconnection customers working their way through the affected system transmission provider's interconnection process.[2034] PPL states that some transmission providers combine interconnection and transmission and argues that removing the word "interconnection" better accommodates such a combined group.

[2031] North Carolina Commission and Staff Initial Comments at 24.

[2032] WAPA Initial Comments at 10-11.

[2033] PJM Initial Comments at 64.

[2034] PPL Initial Comments at 19-20.

1049. Several commenters ask for clarification or modification of the terms "affected system" or "affected system operator." National Grid asserts that the Commission should clarify whether an affected system solely includes transmission owners in each region or also includes neighboring RTOs/ISOs or transmission providers in neighboring regions.[2035] NRECA requests that the Commission clarify the scope of several definitions so that transmission providers will not overlook a proposed interconnection request's impact on an electric cooperative's affected system.[2036]

(2) Notification of Affected System Impacts

1050. Regarding the proposed triggering event at the close of (1) the cluster request window, (2) the customer engagement window, (3) the cluster study, or (4) the cluster restudy for a host transmission provider to notify an affected system operator, PacifiCorp argues that the 10-business day notification obligation begins with an ill-defined standard in the NOPR—the "close of first event giving rise to the identification of an affected system impact."[2037] PacifiCorp requests that the Commission clarify this standard and

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[2035] National Grid Initial Comments at 35.

[2036] NRECA Initial Comments at 9, 36-39. More specifically, NRECA contends that because some transmission providers interpret the definition of "Affected System" to mean a Commission-jurisdictional transmission system and refuse to recognize that other electric systems may be affected systems, under the *pro forma* LGIP and *pro forma* LGIA, the Commission should provide that an "Affected System" means any affected "electric system," not just an affected "Transmission System," and that an "Affected System Operator" means any "entity that operates an Affected System," not just a transmission owner or transmission provider. *Id.* at 36-37, 39.

[2037] PacifiCorp Initial Comments at 36.

further clarify that transmission providers will not be penalized if affected system issues are not discovered until later in the interconnection process, as such impacts may not always be readily apparent.

1051. Some commenters oppose the proposed requirement in section 3.6.1 of the *pro forma* LGIP that a host transmission provider, within 10 business days of the triggering event that identifies a potential affected system impact, notify an affected system operator of such potential impact.[2038] WAPA states that the initial notification requirement could unnecessarily increase costs because the notification could be received before the system impact study on the host transmission provider's transmission system is complete and thus before any potential network upgrades are identified. Duke Southeast Utilities assert that the notification time frame should be 15 business days because: (1) the host transmission provider may need additional time to notify multiple affected system operators of a potential impact within the same prescribed time frame; and (2) the host transmission provider may need additional time to gather all necessary information and compile adequate notification packages, due to the need to include a technical basis for the affected system impact.[2039] CAISO states that the Commission should require transmission providers to begin the notification process shortly after interconnection customers receive their initial study results and face higher financial requirements to

[2038] *Id.*; CAISO Initial Comments at 27; Duke Southeast Utilities Initial Comments at 12; PG&E Reply Comments at 5; WAPA Initial Comments at 11.

[2039] Duke Southeast Utilities Initial Comments at 12.

proceed in the interconnection queue.[2040] CAISO explains that this is when the majority of interconnection customers withdraw their interconnection requests because they do not wish to put more money at risk. CAISO argues that using this smaller pool of interconnection requests will enable faster affected system studies due to decreased volume and more realistic study assumptions.

1052. A few commenters provide suggestions on the content of the notice that the host transmission provider sends to the affected system operator. Specifically, APPA-LPPC propose that *pro forma* LGIP section 3.6.1 be revised to include the following: "Along with notification to Interconnection Customer of the list of potential Affected Systems, Transmission Provider will notify Interconnection Customer and such Affected Systems whether a single set of studies (Feasibility, System Impact and Facilities Studies) may be sufficient to manage all related impacts. A single set of studies may be undertaken upon agreement of all parties."[2041] Duke Southeast Utilities suggest that, in addition to such notification, the host transmission provider should provide evidence of the potential impact, which they assert will assist the affected system operator in: (1) understanding the host transmission provider's engineering analysis and assumptions that led it to identify the potential impact; and (2) determining whether to conduct an affected system study.[2042]

[2040] CAISO Initial Comments at 29.

[2041] APPA-LPPC Initial Comments at 25-26.

[2042] Duke Southeast Utilities Initial Comments at 13.

1053. Regarding to whom the host transmission provider should send the notification, NRECA argues that the notification requirement should extend to all potential affected systems and any affected system operators to allow electric cooperative affected system transmission providers to coordinate with the transmission provider and interconnection customer to timely address any affected system impacts.[2043] Tri-State states that *pro forma* LGIP section 3.6.1 needs clarification as to whom the notice is to be directed.[2044]

1054. Other commenters oppose the proposed requirement in sections 3.6.2 and 9 of the *pro forma* LGIP that affected system transmission providers must respond to the notification of affected system impacts within 15 business days.[2045] Bonneville advocates that the response time be flexible and allow for reasonable extensions.[2046] Bonneville argues that, if affected system transmission providers only have 15 business days to respond, they will need to err on the side of caution, which could lead to more affected system studies than necessary, resulting in study delays. Duke Southeast Utilities assert that the response time frame should be 20 business days, as the affected system transmission provider may need additional time if: (1) it has received multiple notifications within the same time frame; (2) it needs to request additional data to

[2043] NRECA Initial Comments at 38-39.

[2044] Tri-State Initial Comments at 28.

[2045] Bonneville Initial Comments at 18; CAISO Initial Comments at 27; PG&E Reply Comments at 5; WAPA Initial Comments at 11.

[2046] Bonneville Initial Comments at 18.

determine if it intends to perform a study; (3) its own staff is limited because of deadlines within its own interconnection process; or (4) it wishes to perform a more detailed review to ensure that performing a study does not become the default approach.[2047] Dominion asserts that a 15-business day requirement could be reasonable if all affected system notifications were provided at the same time.[2048] Dominion contends that piecemeal notifications make it difficult for an affected system transmission provider to know if an affected system study is needed until all requests are received.

1055. Additionally, a few commenters contend that the NOPR proposal was unclear what would happen if an affected system operator fails to respond within 15 business days. Enel and ENGIE contend that it is unclear what the consequence is for an affected system transmission provider's failure to meet the response deadline.[2049] Enel encourages the Commission to add language to the *pro forma* LGIP to provide that the affected system transmission provider will forfeit its right to perform an affected system study if it fails to meet the response deadline, as a lack of incentive (and relevant penalty) to respond could result in delayed study results.[2050] ENGIE suggests that the affected

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[2047] Duke Southeast Utilities Initial Comments at 13 (noting that PJM often sends notice of multiple potential impacts from a single cluster).

[2048] Dominion Initial Comments at 37-38.

[2049] Enel Initial Comments at 59-60; ENGIE Initial Comments at 8.

[2050] Enel Initial Comments at 59-60; *see also* Invenergy Initial Comments at 42-44.

system transmission provider bear any financial consequences.[2051] Pacific Northwest Utilities note that the non-jurisdictional affected system operator is not required to respond to the requirements under proposed *pro forma* LGIP section 3.6.1 and may not have the mechanisms in place to respond within 15 business days.[2052]

(3) <u>Timing of Affected System Studies</u>

1056. Several commenters argue that beginning affected system studies too early may yield unreliable results that could lead to restudies and late-stage withdrawals, among other problems.[2053] NextEra asserts that it is unlikely that the host transmission provider could provide useful information to the affected system transmission provider at an earlier stage.[2054] CAISO and Idaho Power argue that the proposal to begin the affected system study process as soon as potential impacts are identified will slow affected system studies or result in unnecessary work for the affected system transmission provider because the impacts will be assessed based on transmission providers' entire interconnection queues, even though many interconnection customers will withdraw early in the interconnection process.[2055]

[2051] ENGIE Initial Comments at 8.

[2052] Pacific Northwest Utilities Initial Comments at 17.

[2053] CAISO Initial Comments at 28-29; Dominion Initial Comments at 37; Enel Initial Comments at 59; Idaho Power Initial Comments at 11; NextEra Initial Comments at 32-33; WAPA Initial Comments at 11-12.

[2054] NextEra Initial Comments at 32-33.

[2055] CAISO Initial Comments at 28-29; Idaho Power Initial Comments at 11.

1057. CAISO takes issue with the proposed deadlines for completing affected system studies and claims that the size of modern interconnection queues makes such quick deadlines impossible. According to CAISO, such deadlines would result in all affected system transmission providers exercising their rights to study every interconnection customer because they have no time to determine whether studies are necessary.[2056]

1058. Invenergy argues that affected system transmission providers should be subject to a deadline for participation in the process.[2057]

1059. Invenergy asserts that, although the NOPR clearly provides that a host transmission provider is not required to pause its interconnection process if an affected system transmission provider does not timely complete its study, the reality is that this could leave interconnection customers in the same position they are in now—being forced under the host transmission provider's timeline to move forward in the study process and to execute an LGIA (and put money at risk) without the benefit of affected system study results. Invenergy contends that the solution is to establish a clear deadline (e.g., LGIA execution) by which time the affected system transmission provider must have completed its studies and identified affected system network upgrades; otherwise, it loses any right to assign affected system network upgrades to an interconnection request in the future. Invenergy states that, if the Commission does not impose such a deadline, it should at least permit interconnection customers that have been forced under host

[2056] CAISO Initial Comments at 27-28.

[2057] Invenergy Initial Comments at 41.

transmission provider's rules to execute LGIAs in the absence of affected system study information to: (1) delay posting security and funding network upgrades under that LGIA until the affected system study results are received; and (2) have the opportunity to withdraw without penalty after receiving affected system study results if the interconnection customer's assigned costs increased by more than 25% compared to costs allocated by the host transmission provider.[2058]

1060. Several commenters argue that an affected system study timeline should be consistent with the cluster study process on the host transmission provider's transmission system because it can impact the host transmission provider's study.[2059] APS requests additional clarification on how the proposed affected system study process correlates to the host system studies and aligns with the host system's requirements.[2060] Enel acknowledges that the 90-calendar day affected system study deadline may be problematic for transmission providers that have 150 calendar days to run the same scope of studies for their own interconnection requests.[2061] AEP stresses the need for coordination between these studies, which it argues would provide the interconnection customer with a more meaningful cost estimate, with coordination resulting in affected

[2058] *Id.* at 25, 43-44.

[2059] APPA-LPPC Initial Comments at 26; AEP Initial Comments at 31; Bonneville Initial Comments at 21; NV Energy Initial Comments at 11.

[2060] APS Initial Comments at 19-20.

[2061] Enel Initial Comments at 65.

system and host system study results being presented around the same time.[2062] Enel contends that the affected system transmission provider should be required to complete any affected system impact studies no later than the host transmission provider's deadline to complete the cluster restudy.[2063] Enel asserts that this initial affected system study should be completed before the interconnection customer must satisfy requirements to enter the facilities study, at which point the interconnection customer faces a higher withdrawal penalty. Enel contends that the NOPR proposal could result in an affected system transmission provider being notified that an affected system study is needed after final results of the cluster restudy are complete, meaning that an affected system study may not be completed until or even after the execution of an LGIA. Enel argues that, after affected system studies are complete, an interconnection customer could have its costs double just before (or even after) an LGIA is executed, and penalty-free withdrawal under proposed *pro forma* LGIP section 3.7.1 would only apply if assigned interconnection costs increase by more than 100%.

1061. Several commenters argue that the timing of affected system studies should be structured to reduce potential burdens. Idaho Power suggests that affected system studies be performed after the initial cluster study to minimize unnecessary work and ensure that only interconnection requests moving into the cluster restudy have their affected system

[2062] AEP Initial Comments at 31-32.

[2063] Enel Initial Comments at 58.

impacts studied.[2064] Dominion notes that PJM recently sought to address timing issues by incorporating affected system studies into later phases of its cluster studies.[2065]

(4) Affected System Scoping Meeting

1062. Several commenters express concern about the proposed requirement in section 3.6.2 of the *pro forma* LGIP that the affected system transmission provider (1) schedule an affected system scoping meeting within seven business days after providing written notification that it intends to conduct an affected system study and (2) hold that meeting within seven business days after it is scheduled.[2066] Bonneville and Dominion assert that holding the scoping meeting within this time frame might not be realistic because these meetings are contingent upon the availability of multiple attendees.[2067] CAISO contends that the proposal to schedule affected system scoping meetings within seven business days is impossible and that affected system transmission providers would simply hold scoping meetings to comply, having had no time to prepare anything meaningful for the

[2064] Idaho Power Initial Comments at 11.

[2065] Dominion Initial Comments at 37 (citing PJM Interconnection, L.L.C., Tariff Revisions for Interconnection Process Reform Transmittal Letter, Docket No. ER22-2110-000, at 55, 59-60 (filed June 14, 2022)).

[2066] *Id.* at 38; Bonneville Initial Comments at 18-19; CAISO Initial Comments at 28; MISO Initial Comments at 86. WAPA also asserts that a meeting after the affected system study is completed would be more beneficial than the proposed affected system scoping meeting, as the proposed meeting would only provide speculative impacts that might be caused by an interconnection request. WAPA Initial Comments at 12.

[2067] Bonneville Initial Comments at 18-19; Dominion Initial Comments at 38.

meeting.[2068] MISO argues that the Commission should allow each pair of transmission providers to develop their own schedule for the scoping process rather than mandating a one-size-fits-all schedule.[2069] MISO asserts that this is particularly true for RTOs/ISOs with joint operating and/or planning agreements, which MISO claims should be able to justify their existing procedures on compliance via the independent entity variation standard. Bonneville emphasizes flexibility and proposes that the phrase "unless otherwise agreed to" be added to this requirement.[2070]

1063. Pacific Northwest Utilities state that, provided that regulated utilities properly invite the non-jurisdictional affected system transmission provider to the affected system scoping meeting, the Commission should clarify that such steps are sufficient to demonstrate that the regulated transmission provider has met its requirements under this section.[2071] Further, Pacific Northwest Utilities note that the non-jurisdictional affected system transmission provider is not required to respond to the requirements under section 3.6.2 of the *pro forma* LGIP and may not be prepared to attend the affected system scoping meeting.

[2068] CAISO Initial Comments at 28.

[2069] MISO Initial Comments at 86.

[2070] Bonneville Initial Comments at 19.

[2071] Pacific Northwest Utilities Initial Comments at 17.

(5) Affected System Study Process

1064. Multiple commenters advocate for changes to the proposed requirement in section 3.6.3 of the *pro forma* LGIP that the transmission provider provide data monthly, or more frequently as needed, regarding the amount and location of generation in the transmission provider's interconnection queue, as well as updated information about the transmission provider's transmission system. NRECA states that the proposed information sharing requirement is essential but should not be limited to notifying or providing data to a transmission provider acting as an affected system operator but should extend to all potential affected systems and any affected system operators to allow electric cooperative affected system operators to perform studies and coordinate with the transmission provider and interconnection customer to timely address any affected system impact.[2072] MISO argues that the Commission should not impose an arbitrary time frame for data reports and suggests that such information should be provided only at times when it changes.[2073] MISO asserts that updates are not likely to be helpful to interconnection customers until the next study stage has been completed. NV Energy requests that the Commission move to quarterly reporting because monthly updates would not be helpful and may provide dramatic swings in study results, which could trigger the need for an affected system study to start over.[2074] NV Energy also requests that assumptions for

[2072] NRECA Initial Comments at 38-39.

[2073] MISO Initial Comments at 86.

[2074] NV Energy Initial Comments at 12.

studies be coordinated between the host transmission provider and affected system operator and that updates become quarterly after the study has been issued.

1065. LADWP requests clarification as to what specific data "updated information about the transmission provider's transmission system" refers.[2075]

1066. Bonneville and Dominion argue that the proposed information sharing requirement is duplicative or unnecessary. Bonneville posits that the requirement is duplicative of information that is already available on OASIS.[2076] Dominion argues that this requirement is overly cumbersome given transmission providers' limited resources and numerous obligations and may produce data that the affected system may not even want or use.[2077] Dominion asserts that it would be more efficient to require the host transmission provider to provide such information upon request.

(6) <u>Affected System Queue Position</u>

1067. Several commenters support the NOPR proposal's first-ready, first-served interconnection queue priority approach in proposed section 9.2 of the *pro forma* LGIP.[2078] OMS and MISO argue that MISO and SPP's recently approved changes to their joint operating agreement to modify the queue priority and coordination rules for

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[2075] LADWP Initial Comments at 4 (citing NOPR, 179 FERC ¶ 61,194 at P 187).

[2076] Bonneville Initial Comments at 19.

[2077] Dominion Initial Comments at 38.

[2078] Alliant Energy Initial Comments at 7; EDF Renewables Initial Comments at 11; Invenergy Initial Comments at 40; MISO Initial Comments at 11-12; NextEra Reply Comments at 5; OMS Initial Comments at 17.

affected system studies conform to the NOPR's proposed approach and are an equitable means for sharing costs for network upgrades amongst interconnection customers in different regions and encourages timely processing of affected system impacts.[2079]

1068. However, Bonneville and NextEra assert that the NOPR does not adequately address the important issue of queue priority coordination.[2080] NextEra argues that the notion of interconnection customers racing to be the first (or perhaps the last) to sign an affected system study agreement as a way of setting queue priority will result in conflict.[2081] NextEra contends that, instead, the goal should be to ensure that transmission providers acting as affected systems perform affected system studies on a timeline that is consistent with the host transmission system's stated schedule so that results are delivered in a timely manner and interconnection customers can be well-informed in their decision making. NextEra recommends that each pair of transmission providers whose interconnection customers affect each other's system enter into agreements, to be filed with the Commission, specifying how they will ensure appropriate queue priority in affected system studies.

1069. Bonneville argues that the queue priority for affected system interconnection requests should be determined by giving priority to an interconnection request in an

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[2079] MISO Initial Comments at 88; OMS Initial Comments at 17 (citing *Sw. Power Pool, Inc.*, 179 FERC ¶ 61,148 (2022)).

[2080] Bonneville Initial Comments at 20; NextEra Reply Comments at 5.

[2081] NextEra Reply Comments at 5.

affected system study over any interconnection request that has not yet started the cluster study on the host transmission system.[2082] Bonneville contends that if an affected system interconnection request receives higher queue priority relative to any interconnection requests for which the host transmission provider has started the cluster study but has not yet provided cluster study reports, then such a queue priority framework would introduce uncertainty into the cluster study process, as an affected system notification could be received during the cluster study process and trigger a restudy, delays, and increased costs to the participants of the cluster study.

1070. Other commenters argue for different approaches to affected system queue priority or allocation of affected system network upgrade costs. ENGIE argues that, although assigning an affected system queue position appears beneficial for assigning network upgrade costs, it could also create delays for the interconnection customer because it would be beholden to two separate interconnection queues.[2083] ENGIE recommends that the Commission allocate network upgrade costs outside of the interconnection queue on an *ex post* basis to avoid the double-queue situation.

1071. Enel asserts that the NOPR's proposed queue priority determination method will result in additional uncertainty about timing of affected system studies, incomplete and inaccurate cluster study results, and the need for restudies.[2084] Although Enel agrees that

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[2082] Bonneville Initial Comments at 20.

[2083] ENGIE Initial Comments at 9.

[2084] Enel Initial Comments at 62-63.

establishing queue priority between host and affected system interconnection requests is essential, Enel disagrees with the NOPR proposal to establish the affected system interconnection request's queue priority according to when the affected system interconnection customer executes an "affected system study."[2085] Enel states that this must be a typo that should say "affected system study agreement." Enel also notes that proposed *pro forma* LGIP section 9.2 does not clearly state which event establishes the date by which an affected system interconnection request receives its queue priority relative to host system interconnection requests and requests clarification on this point.[2086] Enel further states that, if affected system queue priority is established based on an individual date, transmission providers would need to process affected system interconnection requests serially rather than by cluster and recommends that the Commission adopt a queue priority framework in which affected system interconnection requests would be studied in the same cluster grouping that the host transmission provider uses.[2087] Enel also recommends that queue priority be assigned based on the deadline for entry into the host transmission provider's interconnection queue.

1072. Several commenters request or propose specific clarifications regarding proposed *pro forma* LGIP section 9.2, including how the proposed first-ready, first-served

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[2085] *Id.* at 61.

[2086] *Id.* at 61-62.

[2087] *Id.* at 62-63.

interconnection queue priority approach interacts with cluster studies.[2088] EDF Renewables recommends that, to better synchronize the host and affected system study processes, the affected system operator should establish queue priority between the host and affected system based on the interconnection request achieving a certain stage in the host system's study process, rather than the date the interconnection request was submitted.[2089] APPA-LPPC ask that the Commission clarify proposed *pro forma* LGIP section 9.2 and the related obligations under *pro forma* LGIP sections 9.8 and 4.2.3.[2090] APPA-LPPC state that, as drafted, proposed *pro forma* LGIP section 9.2 suggests a queue position for an interconnection customer independent of ongoing and pending cluster studies while *pro forma* LGIP section 9.8 and cross-referenced *pro forma* LGIP section 4.2.3 contemplate the allocation of associated costs incurred by affected systems in the context of a cluster study.

1073. Additionally, MISO recommends that the final rule clarify an enforcement mechanism, such as loss of relative queue priority used under the MISO-SPP joint operating agreement, for the proposed first-ready, first-served interconnection queue priority approach.[2091]

[2088] APPA-LPPC Initial Comments at 26; Idaho Power Initial Comments at 11; NextEra Initial Comments at 33.

[2089] EDF Renewables Initial Comments at 11.

[2090] APPA-LPPC Initial Comments at 26.

[2091] MISO Initial Comments at 89.

(7) Affected System Study Agreement

1074. Dominion and Duke Southeast Utilities suggest doubling the amount of time that transmission providers would have under proposed *pro forma* LGIP section 9.3 to tender an affected system study agreement after sharing the schedule for the affected system study.[2092] Duke Southeast Utilities assert that it usually takes more than five business days to receive all needed interconnection request information to draft an affected system study agreement (an often iterative process).[2093] Duke Southeast Utilities state that more time will help affected system transmission providers that may need to draft numerous affected system study agreements within the same time frame.

1075. Bonneville requests clarification as to whether the failure to execute the affected system study agreement, execute the affected system facilities construction agreement, or provide the affected system study deposit would be grounds for removal from the host transmission provider's interconnection queue.[2094]

(8) Affected System Study Scope and Timeline

1076. Many commenters, including transmission providers, argue that the Commission should clarify the scope of required affected system studies by addressing whether an affected system facilities study will be required under section 9 of the *pro forma*

[2092] Dominion Initial Comments at 38; Duke Southeast Utilities Initial Comments at 14.

[2093] Duke Southeast Utilities Initial Comments at 14.

[2094] Bonneville Initial Comments at 20-21.

LGIP.[2095] For example, Duke Southeast Utilities state that the NOPR proposal is unclear on whether "affected system study results" is intended to reflect the results of a system impact study, a facilities study, or a combination thereof.[2096]

1077. Several commenters request that the Commission explicitly include a facilities study in the affected system study process.[2097] Duke Southeast Utilities, Enel, NV Energy, and SPP assert that explicitly including a facilities study in the affected system study process would provide both affected system transmission provider and affected system interconnection customer with more refined estimated costs and construction timelines.[2098] Pattern Energy argues that a facilities study is a useful tool for scoping and pricing network upgrades and other facilities necessary to mitigate transmission-related contingencies,[2099] and LADWP argues that a facilities study would improve the efficiency of the overall process by minimizing discrepancies discovered after execution of a construction agreement.[2100] APPA-LPPC request that the Commission confirm that

[2095] APPA-LPPC Initial Comments at 26; Duke Southeast Utilities Initial Comments at 15; Enel Initial Comments at 65; Pattern Energy Initial Comments at 24.

[2096] Duke Southeast Utilities Initial Comments at 15.

[2097] *Id.*; APPA-LPPC Initial Comments at 26; Enel Initial Comments at 65; LADWP Initial Comments at 4; NV Energy Initial Comments at 11; Pattern Energy Initial Comments at 25; SPP Initial Comments at 16-17.

[2098] Duke Southeast Utilities Initial Comments at 15; Enel Initial Comments at 65; NV Energy Initial Comments at 11; SPP Initial Comments at 16-17.

[2099] LADWP Initial Comments at 4; Pattern Energy Initial Comments at 24-25.

[2100] LADWP Initial Comments at 4.

it does not intend to foreclose the possibility of affected system facilities studies being conducted, as a facilities study is needed to ascertain the precise nature of any network upgrades that an interconnection customer may cause.[2101]

1078. Shell argues for including further information regarding local transmission planning from neighboring transmission providers in affected system study results because early identification of all transmission-related mitigation will ensure that interconnection customers can anticipate affected system network upgrades as early as possible.[2102]

1079. Several commenters, including transmission providers, argue that the 90-calendar day time frame for completion of the affected system study, from the date an affected system transmission provider receives an executed affected system study agreement from the affected system interconnection customer to the date the affected system transmission provider presents the affected system study report to the affected system interconnection customer, as proposed in *pro forma* LGIP section 9.6, does not provide affected system transmission providers sufficient time to complete the study.[2103] Bonneville requests that the Commission clarify whether the schedule to complete the affected system study could include a due date that is in excess of the 90-calendar day timeline.[2104] Tri-State requests

[2101] APPA-LPPC Initial Comments at 26.

[2102] Shell Initial Comments at 31.

[2103] AEP Initial Comments at 31; WAPA Initial Comments at 13.

[2104] Bonneville Initial Comments at 19.

the addition of "and deposit" to proposed *pro forma* LGIP section 9.6, such that the 90-calendar day period would begin after the receipt of the executed affected system study agreement and deposit.[2105] MISO requests that the Commission clarify that the study clock would commence only after all necessary data has been received.[2106]

1080. Other commenters support the NOPR proposal or argue that affected system interconnection customers should be given the results of affected system studies as early as possible. Interwest states that it agrees with commenters that the proposed 90-calendar day time limit, combined with monetary penalties, will help instill discipline and support investments needed to meet the timelines.[2107] Shell asserts that affected system study results must be provided before or in conjunction with system impact study results on the host transmission system, or at the latest, before interconnection customers are required to proceed to the facilities study on the host transmission system, as interconnection customers typically pursue financing after receiving system impact study results and before advancing to the facilities study and doing so will avoid last minute network upgrade costs that undermine project viability and cause interconnection queue withdrawals.[2108] Shell supports an option for interconnection customers to pause the interconnection study process on the host transmission system for an affected system

[2105] Tri-State Initial Comments at 19.

[2106] MISO Initial Comments at 93.

[2107] Interwest Reply Comments at 17.

[2108] Shell Initial Comments at 30-31.

study to "catch-up" if such an option lowers the risk of receiving late affected system study results. Similarly, Interwest asserts that affected system interconnection customers should be permitted to delay posting security and funding network upgrades, if there are delays in affected system studies, which Interwest contends is a reasonable accommodation that allows such affected system interconnection customers to reduce risks.[2109]

1081. Additionally, WAPA expresses concern about its ability to tender an affected system facilities construction agreement to an interconnection customer within 30 calendar days of providing the affected system study report, as proposed in *pro forma* LGIP section 9.9.[2110]

1082. Several commenters oppose, ask for clarification, or propose alternatives regarding the scope and applicability of the financial penalties that would apply if a transmission provider does not meet the study completion deadlines set forth in proposed *pro forma* LGIP section 9.6. AECI asserts that, so long as affected system transmission providers are using good utility practice and appropriate due diligence to complete affected system studies, there is no benefit of imposing additional penalties on affected

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[2109] Interwest Reply Comments at 18.

[2110] WAPA Initial Comments at 13.

system transmission providers.[2111] ENGIE states that it is unclear who bears the financial penalties for late affected system studies.[2112]

1083. MISO, in contrast, interprets the NOPR proposal as applying penalties only to the affected system transmission provider, and recommends that the Commission recognize that some delays may be beyond the control of the affected system transmission provider and not penalize affected system transmission providers for third-party delays.[2113] Similarly, Duke Southeast Utilities express concern that penalties could be levied against affected system transmission providers for delays beyond their control, and further argue that the Commission should consider imposing multilateral penalties on all entities in accordance with their individual obligations set forth in the proposed process.[2114]

1084. Several commenters state that the cost estimates provided in affected system study results should be non-binding, or that certain types of cost increases related to affected system study results should allow interconnection customers to withdraw their

[2111] AECI Initial Comments at 7.

[2112] ENGIE Initial Comments at 9. Additionally, ENGIE states that transmission owners typically have responsibilities for affected system studies and, therefore, argues that the Commission should consider language that distributes financial risk and penalties to both transmission owners and transmission providers, including an ability for transmission providers to recover costs from transmission owners. *Id.*

[2113] MISO Initial Comments at 92. WAPA also is generally concerned about the imposition of monetary penalties for failure to meet deadlines and questions whether federal agencies like WAPA should, or even can be, subject to monetary penalties. *See* WAPA Initial Comments at 10, 14.

[2114] Duke Southeast Utilities Initial Comments at 17-18.

interconnection requests without penalty.[2115] Similarly, Shell asserts that the Commission should allow penalty-free withdrawals in the event of late affected system network upgrade costs that surpass a certain threshold, arguing that such circumstances are beyond the interconnection customer's control.[2116] PacifiCorp states that any cost estimates identified by affected system operators should be non-binding, given that they could be subject to change.[2117]

1085. Pattern Energy believes that the Commission should provide incentives for transmission providers to provide more reasonable and accurate cost estimates for network upgrades and related facilities, even for affected system studies.[2118] Pattern Energy claims that the Commission should not adopt "good faith" to be the standard on which cost estimates are provided in affected system studies, asserting that reasonable cost estimates based on defined metrics should be the standard.

(9) Affected System Network Upgrade Cost Allocation

1086. SEIA supports the NOPR proposal to allocate affected system network upgrade costs using a proportional impact method, arguing that this method should help to reduce individual interconnection customer network upgrade costs by allowing interconnection

[2115] Invenergy Initial Comments at 25; Shell Initial Comments at 31; PacifiCorp Initial Comments at 36.

[2116] Shell Initial Comments at 31.

[2117] PacifiCorp Initial Comments at 36.

[2118] Pattern Energy Initial Comments at 25.

customers to share the cost and, in doing so, reduce the likelihood of cascading withdrawals.[2119]

1087. Other commenters stress the importance of certainty and fairness in cost allocation rules. For example, National Grid contends that cost allocation rules should provide certainty to interconnection customers at a reasonable point in the interconnection process, while also having appropriate rules to allocate changes in cost allocations that arise after the date that network upgrade costs are finalized.[2120] National Grid suggests that this could be achieved by finalizing network upgrade cost allocations at the facilities study phase of the host transmission provider's interconnection study process, subject to risk sharing cost allocation rules, whereby later changes due to the identification of additional required facilities could be shared between the interconnection customer and load in a transmission provider's footprint based on the principle of beneficiary pays, through various particular methodologies, including those used for transmission planning upgrades or those based on geography.[2121]

1088. Finally, several commenters raise other issues regarding affected system cost allocation. Enel seeks clarity regarding whether shared network upgrades would apply between host system interconnection requests and affected system interconnection

[2119] SEIA Initial Comments at 35.

[2120] National Grid Initial Comments at 35.

[2121] Interwest Reply Comments at 17; National Grid Initial Comments at 35-36.

requests.[2122] NV Energy asserts that, since the affected system interconnection request is queued, if the affected system interconnection customer is allocated affected system network upgrade costs based on the proportional impact method and subsequentially withdraws, then a restudy could potentially be required for a lower-queued cluster, which would result in a misalignment with the timeline and withdrawal penalties in the transmission provider's cluster study for native interconnection requests.[2123] ACE-NY argues that no project should be assigned affected system network upgrade costs after it executes its LGIA and/or after the interconnection customer has accepted its cost allocation in the class year process in NYISO.[2124]

(10) Tender of Affected System Facilities Construction Agreement

1089. Several commenters argue that the proposed time frame for the affected system transmission provider to tender an affected system facilities construction agreement to the affected system interconnection customer—within 30 calendar days of providing the affected system study results to the interconnection customer, as proposed in section 9.9 of the *pro forma* LGIP—should be extended or modified. Duke Southeast Utilities argue that this deadline should be 60 calendar days for various administrative reasons.[2125]

[2122] Enel Initial Comments at 67 (citing proposed *pro forma* LGIP sections 9.8 and 3.10).

[2123] NV Energy Initial Comments at 11.

[2124] ACE-NY Initial Comments at 9.

[2125] Duke Southeast Utilities Initial Comments at 15-16 (citing the possibility of multiple individual agreements, the need to refine previously provided cost estimates and

Idaho Power suggests that the affected system transmission provider tender the affected system facilities construction agreement either within 60 calendar days after the interconnection customers executes a facilities construction agreement with the host transmission provider or within 30 calendar days after providing the affected system study results to the affected system interconnection customer, if the affected system study is performed during the interconnection facilities study.[2126] Idaho Power explains that information required in the facilities construction agreement is comparable to the information provided by the host transmission provider in the interconnection facilities study report, which, according to Idaho Power, provides a reasonably accurate timing and cost estimate and requires considerable coordination to develop. WAPA highlights other constraints, stating that it contracts out many of its facilities study tasks, which can take significant time, that it must work within the budgetary constraints of its annual appropriation, and that it is impractical to have a construction agreement ready for any interconnection customer within 30 calendar days.[2127]

1090. MISO cautions that providing detailed affected system network upgrade cost estimates and construction timelines within 30 calendar days of providing the affected system study results may not be feasible given that MISO currently only gives high-level

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necessary construction schedule, and the potential for more information and updates from the host transmission provider).

[2126] Idaho Power Initial Comments at 11.

[2127] WAPA Initial Comments at 13.

cost estimates after its affected system study and construction timelines and detailed cost estimates are provided in the affected system network upgrade facilities study, which is performed by transmission owners.[2128] MISO further argues that it should not be responsible for actions that are beyond its control, such as the transmission owner-prepared affected system network upgrade facilities study, which it claims would not be feasible to include in each affected system study report if it is attempting to meet the 90-calendar day study timeline, and thus the affected system study and the affected system facilities study should be kept separate. MISO further argues that it is unlikely that transmission owners could provide cost/schedule detail with +/- 20% accuracy within 30 calendar days of determination of affected system network upgrade obligations, with 90 calendar days being a more reasonable time frame.[2129]

(11) <u>Restudy</u>

1091. Bonneville expresses concern with the restudy timeline proposed in *pro forma* LGIP section 9.10, which would require that a restudy of the affected system study take no longer than 60 calendar days from the date of notice. Bonneville argues that flexibility is warranted due to the complexity of restudies.[2130]

[2128] MISO Initial Comments at 90-91.

[2129] *Id.* at 91-92.

[2130] Bonneville Initial Comments at 22.

(d) **Requests for Alternatives**

(1) **Clustering of Affected System Studies**

1092. Several commenters argue that transmission providers should process affected system studies using a clustering approach.[2131] Several commenters argue that mandating use of serial studies for all variously situated transmission providers would adversely impact the efficiency of the study process and place a significant administrative burden on transmission providers that is disproportionate to the contemplated benefits.[2132] NextEra urges the Commission to not mandate serial affected system study processing when cluster studies of affected system impacts will be more expeditious and efficient, contending that this would particularly be the case when interconnection requests in large cluster studies impact an adjacent system.[2133] North Carolina Commission and Staff claim that serial studies come with substantial costs in the form of network upgrades that may not be sufficient to meet future demand.[2134]

[2131] AECI Initial Comments at 6; Indicated PJM TOs Initial Comments at 47; NextEra Reply Comments at 4; North Carolina Commission and Staff Initial Comments at 25; PPL Initial Comments at 19-20; SPP Initial Comments at 15; WAPA Initial Comments at 11.

[2132] AECI Initial Comments at 6-7; Indicated PJM TOs Initial Comments at 47; NextEra Reply Comments at 4; North Carolina Commission and Staff Initial Comments at 24-25 (citing Gajda Aff. ¶¶ 21-22, 27); SPP Initial Comments at 15-16.

[2133] NextEra Reply Comments at 4-5.

[2134] North Carolina Commission and Staff Initial Comments at 25 (noting that Duke Energy Progress, LLC constructed $711,805 in affected system network upgrades in 2017 to accommodate a PJM cluster and that a current, planned upgrade of the same transmission line will eliminate the need for all or some of those affected system network upgrades, which should have lasted at least 40 years and were paid for by Duke Energy

1093. Indicated PJM TOs argue that, for efficiency and consistency, affected system studies should be integrated into the cluster study process.[2135] Indicated PJM TOs argue that PJM's proposed approach, whereby an affected system study identified by one region would be integrated into the cluster study of another region, would be more efficient and less disruptive than the approach identified in the NOPR.[2136]

1094. Some commenters also call for flexibility. AECI argues that the Commission should not limit the flexibility yielded by its existing process of studying each yearly cluster to determine impacts and potential affected system network upgrades, when it is acting as the affected system operator coordinating studies with a neighboring RTO/ISO.[2137] PPL argues that affected system transmission providers should have the option to enter into a study agreement with either an individual affected system interconnection customer, a group of affected system interconnection customers from the

Progress, LLC's customers).

[2135] Indicated PJM TOs Initial Comments at 47-48; Indicated PJM TOs Reply Comments at 41.

[2136] Indicated PJM TOs Initial Comments at 47 (noting that the 2022 PJM filing provides that PJM will determine the need for an affected system analysis in phase 1 of a study cycle, and when PJM is identified by another region as needing to complete an affected system analysis, it will place the affected system interconnection request in phase 2 of an ongoing study cycle) (referencing PJM, Filing, Docket No. ER22-2110-000, Sims Aff. ¶ 10 (filed June 14, 2022)).

[2137] AECI Initial Comments at 6.

same cluster (that share cost and other responsibilities), or the "direct connect system."[2138]

(2) <u>Coordination Between Host Transmission Provider and Affected System Transmission Provider</u>

1095. NextEra contends that the NOPR proposal gives too little attention to complex issues, such as potential interconnection queue coordination issues between transmission providers that could arise after implementation of the proposed reforms.[2139] Several commenters argue that, for efficiency reasons, host transmission providers—and not individual affected system interconnection customers—should be required to coordinate affected system study activities with the affected system transmission providers.[2140] Some commenters recommend that the Commission adopt the coordination approach used by MISO and certain of its neighboring systems, whereby the host transmission provider coordinates all technical data, study deposits, and studies with the affected system transmission provider rather than the proposed direct communication and coordination between interconnection customer and affected system transmission provider.[2141] Enel asserts that this would reduce administrative burden, ensure timely

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[2138] PPL Initial Comments at 20.

[2139] NextEra Reply Comments at 4.

[2140] Enel Initial Comments at 60-61; North Carolina Commission and Staff Initial Comments at 25-26; Shell Initial Comments at 30.

[2141] Enel Initial Comments at 60-61. Enel further argues that affected system studies should be invoiced to the host transmission provider and paid out of the interconnection customer's study deposits, subject to total study cost true-up, and that

compliance with the tariff, reduce interconnection costs, and increase accountability. Enel also argues that using the host transmission provider's study agreement to require the interconnection customer to comply with the affected system transmission provider's study process ensures that the interconnection customer must meet tariff deadlines and cannot delay the affected system transmission provider's studies. In addition, Shell states that that the Commission should develop guidance for situations in which neighboring transmission providers disagree on the scope and/or timing of an affected system study.[2142]

1096. Several commenters argue that the NOPR proposal should be reevaluated or modified regarding whether and when transmission providers conducting cluster studies would be required to delay those studies to wait for the results of affected system studies. Pattern Energy contends that the Commission should consider an approach in which host transmission providers are not required to wait for affected system studies to be completed, if such delayed action would result in a study milestone being missed.[2143] Pattern Energy seeks to avoid an unintentional "delay loop," whereby the affected system

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host transmission providers should be required to share the interconnection customer's technical data as needed. Enel reasons that through direct connections, host and affected system transmission providers would be better able to compare constraints and proposed upgrades to coordinate where a single upgrade may address constraints on both transmission systems. *Id*.

[2142] Shell Initial Comments at 30.

[2143] Pattern Energy Initial Comments at 25.

is not diligently processing an affected system study because the host transmission provider is waiting for it.[2144]

1097. In contrast, PacifiCorp requests that the Commission clarify that, although host transmission providers performing cluster studies are not required to delay those studies by waiting for the results of affected system studies, transmission providers will not be prohibited from delaying the cluster study process to account for affected system study issues if the host transmission provider determines that the cluster study cannot progress without the results of the affected system studies.[2145] MISO raises similar concerns about a transmission provider proceeding with its cluster studies without affected system data, which it asserts is critical information for an interconnection customer.[2146] MISO further asserts that the NOPR proposal will not provide useful information to the interconnection customer sooner and will increase uncertainty, opportunities for late-stage withdrawals, cost shifts, and unscheduled restudies and cascading withdrawals.[2147]

1098. Xcel strongly supports improving affected system study interactions, arguing that with common models and processes, in many instances, host transmission provider study results can be used to identify affected system network upgrades, leaving the affected

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[2144] *Id.* at 25-26.

[2145] PacifiCorp Initial Comments at 36-37.

[2146] MISO Initial Comments at 93-94.

[2147] *Id.* at 94-95.

system transmission provider to only identify mitigation solutions.[2148] Noting that many RTO/ISO regions have operating agreements that address interface capacity rights and processes to relieve congestion near and across seams, Xcel argues that host and affected system transmission providers should take those operating agreements into account when considering any interconnection-related requirements from the affected system transmission provider.

1099. APPA-LPPC request that transmission providers be able to forego a formal affected system study when studies by the host transmission provider may be sufficient.[2149] APPA-LPPC ask the Commission to recognize in the *pro forma* LGIP that there may be instances in which separate affected system studies may not be necessary or useful because, in their members' experience, particularly in the Western Interconnection, feasibility, system impact, and facilities studies undertaken by a directly interconnecting transmission provider may be adequate in scope to encompass impacts on and any necessary upgrades to an affected system.[2150] In such a case, APPA-LPPC state, a unitary study would be less expensive for all parties and avoid a complex administrative task of sequencing and integrating separate system studies.[2151]

[2148] Xcel Initial Comments at 38-39.

[2149] APPA-LPPC Initial Comments at 25.

[2150] *Id.* at 23-25.

[2151] *Id.* at 25.

1100. Another alternative proposed by WAPA and Enel is the use of an affected system screening process to identify instances where affected system studies will be needed.[2152] WAPA suggests that this screening process could be a feasibility-level study, completed for an entire cluster, to narrow down which interconnection requests within the cluster potentially have impacts on an affected system.[2153] WAPA contends that, without a screening process, transmission providers under the NOPR proposal will require affected system studies by default. Enel suggests that the affected system transmission provider should conduct the screening process during the host transmission provider's cluster study so that the affected system transmission provider is prepared to perform its affected system study during the host transmission provider's initial cluster restudy.

(3) Interregional Transmission Planning

1101. A few commenters urge the Commission to address affected system impacts as a systematic phenomenon and a matter of interregional transmission planning, rather than one-off events to be handled serially.[2154] EDF Renewables argues that better interregional transmission planning should reduce the frequency and severity of affected system impacts, asserting that a system-wide approach is more efficient than a piecemeal

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[2152] Enel Initial Comments at 57-58; WAPA Initial Comments at 12-13.

[2153] WAPA Initial Comments at 12-13.

[2154] EDF Renewables Initial Comments at 11; NextEra Initial Comments at 31; North Carolina Commission and Staff Initial Comments at 3.

one.[2155] NextEra cautions that one issue absent from the affected system proposals in the NOPR is that the costs for alleviating an existing system condition should not rest with a new generating facility interconnecting on an adjacent system that did not create the problem.[2156] NextEra argues that preexisting reliability issues should instead be identified and solved through the transmission planning processes.

(e) Requests for Clarification and Flexibility

1102. Idaho Power requests clarification regarding whether the affected system study process would be required for entities that already use the first-ready, first served cluster study process.[2157]

1103. Regarding timing, Invenergy argues that although many of the NOPR's proposed requirements should apply prospectively to new interconnection requests, immediate action from the Commission is needed to resolve affected system issues. Invenergy requests that the Commission clarify that the proposed reforms should apply to all pending interconnection requests and active studies.[2158]

1104. Several commenters request clarification regarding how the proposed affected system reforms would affect RTO/ISO transmission providers and transmission owners

[2155] EDF Renewables Initial Comments at 11.

[2156] NextEra Initial Comments at 31.

[2157] Idaho Power Initial Comments at 11.

[2158] Invenergy Initial Comments at 41.

in their regions.[2159] Eversource requests that the Commission clarify that the proposed affected system reforms are not applicable to intra-RTO/ISO system upgrades.[2160] Similarly, NYTOs request that the Commission clarify that the proposed affected system reforms would not apply to neighboring transmission owners within a single RTO/ISO, or at least allow such transmission owners to demonstrate on compliance that their existing processes already address such intra-RTO/ISO issues.[2161] AEP requests that the Commission address what it terms the four primary types of affected system scenarios: neighboring transmission owner systems within one RTO/ISO; neighboring transmission owner systems in two separate RTOs/ISOs; a transmission owner system in an RTO/ISO neighboring a non-RTO/ISO transmission provider; and neighboring transmission providers both outside of an RTO/ISO.[2162] AEP contends that the Commission appears to conflate all possible affected system scenarios in the NOPR, even though the nature of any affected system study can be impacted by the type of scenario.[2163]

1105. CREA and NewSun seek clarification on whether the proposed affected system reforms apply where QF interconnections under PURPA are subject to state

[2159] Eversource Initial Comments at 31-32; NYTOs Initial Comments at 29.

[2160] Eversource Initial Comments at 31-32.

[2161] NYTOs Initial Comments at 29 (citing NYISO, NYISO Tariffs, attach. X, § 30.3.5 (16.0.0)).

[2162] AEP Initial Comments at 32-33; NextEra Reply Comments at 4.

[2163] AEP Initial Comments at 33.

jurisdiction.[2164] CREA and NewSun explain that, under existing precedent, the Commission has allowed states to retain their historic interconnection jurisdiction under PURPA where the QF sells its entire net output to the interconnecting utility.[2165] CREA and NewSun argue, though, that where affected system issues are involved, the state's jurisdiction over the sale of the QF's energy to a utility regulated by that state would not extend to affected system issues with a third-party transmission provider that is not purchasing the QF's net output.[2166] CREA and NewSun urge the Commission to clarify that a QF interconnection customer has the option to opt into use of the Commission's interconnection procedures, in cases where the interconnection requires studies or network upgrades on an affected system without loss of queue position. CREA and NewSun also argue that the QF should retain the right to elect to proceed through the state process in case the QF concludes that it would be less disruptive to do so.

1106. Several commenters request clarification on whether the proposed affected system reforms apply to non-Commission-jurisdictional transmission providers.[2167] Invenergy and Interwest state that, if an affected system is not a Commission-jurisdictional utility,

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[2164] CREA and NewSun Initial Comments at 86.

[2165] *Id.* at 87 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 813-815; *Prior Notice & Filing Requirements Under Part II of the Fed. Power Act*, 64 FERC ¶ 61,139, at 61,991-92, *order on reh'g*, 65 FERC ¶ 61,081 (1993)).

[2166] *Id.* at 87-88.

[2167] Interwest Reply Comments at 18; Invenergy Initial Comments at 42; Pacific Northwest Utilities Initial Comments at 17; Puget Sound Initial Comments at 7; Tri-State Initial Comments at 20.

the Commission would be unable to enforce the process or any penalties proposed in the NOPR, which would leave the interconnection customer in the same bind that currently exists.[2168] Invenergy, Interwest, Xcel, and EEI assert that the Commission should prevent non-jurisdictional entities from interfering with completion of jurisdictional transmission providers' interconnection processes.[2169]

1107. Several commenters call for the Commission to explain how jurisdictional transmission providers should respond to potential delays or inaction by non-jurisdictional transmission providers not subject to the affected system study process reforms.[2170]

1108. Other commenters argue that the Commission should hold jurisdictional transmission providers harmless for delays induced by or notifications not sent by non-jurisdictional affected system transmission providers.[2171] Pacific Northwest Utilities and Puget Sound ask the Commission to clarify that transmission providers have met their obligations in dealing with non-jurisdictional entities if the host transmission provider notifies a non-jurisdictional affected system transmission provider within 10 business

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[2168] Interwest Reply Comments at 18; Invenergy Initial Comments at 42.

[2169] EEI Initial Comments at 19; Interwest Reply Comments at 18; Invenergy Initial Comments at 43; Invenergy Reply Comments at 9; Xcel Initial Comments at 39.

[2170] EEI Initial Comments at 19; NextEra Initial Comments at 34; Pacific Northwest Utilities Initial Comments at 15-16; Xcel Initial Comments at 39.

[2171] Pacific Northwest Utilities Initial Comments at 16-17; Puget Sound Initial Comments at 7.

days of identifying a potential impact to the transmission system of the non-jurisdictional entity, pursuant to *pro forma* LGIP section 3.6.1, and invites the non-jurisdictional entity to an affected system scoping meeting, pursuant to *pro forma* LGIP section 3.6.2.[2172]

1109. Many commenters emphasize the importance of flexibility for transmission providers and argue in favor of granting transmission providers compliance flexibility in implementing affected system study process reforms.[2173] Some commenters contend that the Commission should allow transmission providers to demonstrate that their existing affected system study processes or planned revisions to those processes are adequate to address the Commission's concerns.[2174]

iii. **Commission Determination**

1110. We adopt, with modifications, the NOPR proposal to establish an affected system study process in, and add several related definitions to, the *pro forma* LGIP. As explained in the NOPR, a detailed affected system study process in the *pro forma* LGIP will prevent the use of ad hoc approaches that may give rise to interconnection customers being treated in an unjust, unreasonable, and unduly discriminatory or preferential

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[2172] Puget Sound Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 17.

[2173] AEP Initial Comments at 5; Dominion Initial Comments at 39; National Grid Initial Comments at 37-38; NYISO Initial Comments at 44; PacifiCorp Initial Comments at 36; PJM Reply Comments at 10.

[2174] AEP Initial Comments at 32; Alliant Energy Initial Comments at 7; MISO Initial Comments at 7, 12-13, 83-85, 95; NYISO Initial Comments at 44; Omaha Public Power Initial Comments at 12; OMS Initial Comments at 17; SPP Initial Comments at 16-18.

manner. We agree with commenters that it will also provide interconnection customers greater certainty regarding expectations throughout the interconnection process, including greater cost certainty, which will lead to fewer late-stage withdrawals and fewer delays. The firm affected system study deadlines will also ensure that the affected system study process moves along expediently, providing clarity, cost certainty, and increased transparency throughout the study process, which will minimize opportunities for undue discrimination. For these reasons, we find that the affected system study process reforms adopted herein are just, reasonable, and not unduly discriminatory or preferential and that they remedy the unjust, unreasonable, and unduly discriminatory or preferential rates resulting from the status quo with regard to affected systems. We further find that such reforms will ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.

1111. We disagree with commenters' concerns that a broadly applied, prescriptive affected system study process may not be helpful or may be unworkable.[2175] Instead, we agree with National Grid that the current status quo is not working and will likely worsen absent intervention.[2176] Although some transmission providers may already have working affected system study processes in place, many do not, creating uncertainty and unreasonable delay in the interconnection process. Further, as discussed below with

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[2175] Dominion Initial Comments at 37; Pacific Northwest Utilities Initial Comments at 15; PJM Initial Comments at 63; SDG&E Reply Comments at 3.

[2176] National Grid Initial Comments at 35.

regard to specific reforms, we adopt several revisions to the NOPR proposal in response to comments to ensure the affected system study process deadlines are reasonable and support efficient processing of interconnection requests. We disagree with commenters who argue that the NOPR proposal does not increase efficiency and note that certain modifications will further increase efficiency.[2177] While certain required steps in the affected system study process may increase the need for communication and coordination between affected system transmission providers, affected system interconnection customers, and/or host transmission providers, we find that the potential burden of such discrete efforts are outweighed by the efficiencies of a standardized and more predictable affected system study process. We further find that defining an affected system study process in the *pro forma* LGIP is necessary to ensure that affected system interconnection customers are not being treated in an unjust, unreasonable, and unduly discriminatory or preferential manner, and to ensure that they can evaluate their costs and make decisions regarding the viability of their generation facilities in a timely manner during the interconnection study process.

(a) Definitions and Applicability (Pro Forma LGIP Sections 1 and 9.1)

1112. We adopt the NOPR proposal, with modification, to include several definitions in section 1 of the *pro forma* LGIP related to the affected system reforms, specifically, “affected system facilities construction agreement,” “affected system interconnection

[2177] Dominion Initial Comments at 36-37; SDG&E Reply Comments at 3; SPP Initial Comments at 17; WAPA Initial Comments at 10.

customer," "affected system network upgrades," "affected system study," "affected system study agreement," and "affected system study report." We find these terms to be necessary to enumerate the affected system transmission provider's responsibilities in the affected system study process.[2178] We also add the terms "multiparty affected system study agreement" and "multiparty affected system facilities construction agreement" to section 1 of the *pro forma* LGIP in light of our adoption of such agreements as part of this final rule, as discussed below. We also add the term "affected system queue position" to the *pro forma* LGIP because we find it helpful to distinguish between an interconnection customer's queue position on the host system versus its queue position on an affected system.

1113. We adopt, with modification, the NOPR proposal to add section 9.1 to the *pro forma* LGIP, titled "Applicability." We find that *pro forma* LGIP section 9.1 clarifies that the transmission provider's obligations in section 9 apply when it is acting as an affected system transmission provider, and we have added clarifying language to resolve ambiguity therein.[2179]

[2178] We note that, in the affected system context, there are certain instances in which we intentionally use lowercase versions of defined terms to deviate from their definitions in section 1 of the *pro forma* LGIP. For example, "generating facility" is, in *pro forma* LGIP section 1, part of the definition of "affected system interconnection customer." In the affected system context, we are referring to a generating facility governed by another transmission provider's LGIP rather than the affected system transmission provider's generating facility as defined in its own LGIP.

[2179] We note that former *pro forma* LGIP section 9, titled "Engineering and Procurement ('E&P') Agreement," is now *pro forma* LGIP section 13.7 to accommodate the new affected system study process section.

1114. In response to PPL's argument that the term "affected system interconnection customer" is confusing and that either another term should be used or "interconnection" should be deleted from the term, we reiterate that the *pro forma* LGIP is written to apply to all transmission providers on a generic basis, meaning transmission providers studying proposed interconnections to their transmission systems (host transmission providers) as well as transmission providers studying the impacts on their own transmission system of proposed interconnections to other transmission providers' transmission systems (affected system transmission providers). In other words, when a transmission provider's transmission system is an affected system, the interconnection customer creating the affected system impact is different from that particular affected system transmission provider's own interconnection customers (i.e., those that propose to interconnect directly to the transmission provider's transmission system) and must be distinguished accordingly in the *pro forma* LGIP. The term "affected system interconnection customer" achieves this goal by distinguishing between the interconnection customer's dual roles in the host transmission provider's study process and the affected system transmission provider's study process.

1115. Further, we disagree with PPL's assertion that some transmission providers combine interconnection and transmission processes, making "interconnection" an unnecessary distinction.[2180] This proceeding involves generic generator interconnection procedures, pursuant to which transmission service request studies are performed

[2180] PPL Initial Comments at 19-20.

independently from interconnection studies.[2181] However, we modify the definition of "affected system interconnection customer" and use other defined terms in the *pro forma* LGIP for additional clarity and consistency.

1116. As explained below, we do not adopt the NOPR proposal to require an affected system scoping meeting and therefore also do not adopt the proposed term "affected system scoping meeting" in section 1 of the *pro forma* LGIP.

1117. We clarify that the terms "affected system" and "affected system operator" retain their existing definitions in *pro forma* LGIP section 1.[2182]

1118. In response to NRECA's request for clarification, we reiterate that the final rule applies to transmission providers and, in the affected system context, to transmission providers that are acting as affected systems per the *pro forma* LGIP definition. Therefore, we decline to expand the scope of several affected systems-related definitions as requested by NRECA because we find NRECA's request to be outside the scope of this proceeding.[2183] In response to National Grid's request for clarification regarding whether an affected system solely includes transmission owners in each region or also

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[2181] *See Tenn. Power Co.*, 90 FERC ¶ at 61,761 (finding that interconnection is an element of transmission service but that the interconnection component of transmission service may be requested separately from the delivery component (i.e., interconnection is distinct from transmission service)).

[2182] An affected system is an electric system other than the transmission provider's transmission system that may be affected by the proposed interconnection. An affected system operator is the entity that operates an affected system. *Pro forma* LGIP section 1.

[2183] *See* NRECA Initial Comments at 9, 36-39.

includes neighboring RTOs/ISOs or transmission providers in neighboring regions, we reiterate that an affected system is defined in section 1 of the *pro forma* LGIP as an electric system other than the transmission provider's transmission system that may be affected by the proposed interconnection.

(b) <u>Identification and Notification of Affected Systems (*Pro Forma* LGIP Sections 3.6.1, 9.2, and 11.2.1)</u>

1119. We adopt, with modification, proposed section 3.6.1 of the *pro forma* LGIP, which sets forth the trigger events for identification of an affected system impact to begin the affected system study process. We modify that section to retain as trigger events the completion of the cluster study and cluster restudy but eliminate the earlier trigger events—the close of the cluster request window and the close of the customer engagement window. While we would expect identification of potential affected system impacts to occur upon the completion of the cluster study, we recognize that an affected system impact may not be identified until a restudy occurs, and we adopt language in *pro forma* LGIP section 3.6.1 to account for such a scenario. Thus, as adopted in *pro forma* LGIP section 3.6.1, we require the transmission provider to notify the affected system operator at the first instance of an identified potential affected system impact, which may occur at the completion of the (1) cluster study or (2) cluster restudy. We also move the affected system transmission provider's obligations to respond to the initial notification under proposed *pro forma* LGIP section 3.6.1 to a new *pro forma* LGIP section 9.2. We find this bifurcation of duties with respect to initial affected system notification for the transmission provider, when acting as host transmission provider and affected system

transmission provider, appropriately sets forth the responsibilities of the transmission provider in the sections describing the conditions for each action.

1120. We also adopt the provision proposed in *pro forma* LGIP section 3.6.1 that provides for the transmission provider to notify an affected system operator of a potential affected system impact caused by the interconnection request within 10 business days of the first trigger event giving rise to the identification of the affected system impact. We modify the provision in proposed *pro forma* LGIP section 3.6.1 for the affected system transmission provider to respond to such notification in writing within 15 business days indicating whether it intends to conduct an affected system study to 20 business days, which we move to *pro forma* LGIP section 9.2, as noted above. We further move to *pro forma* LGIP section 9.2 the requirement that, within 15 business days of the affected system transmission provider's affirmative response of its intent to conduct an affected system study, the affected system transmission provider must share a non-binding good faith estimate of the cost and schedule to complete the affected system study.

1121. As adopted, the identification and notification process is tied to the completion of the cluster study or the cluster restudy. At that point, the host transmission provider will have a stronger basis for deciding whether an interconnection request will potentially impact an affected system. Further, the initiation of the affected system study process after the initial study costs are received should lead to affected system study results that provide greater cost certainty, as the largest number of interconnection request withdrawals will most likely occur after receipt of the initial cluster study results, a point

noted by commenters.[2184] After receipt of the initial cluster study results, those interconnection requests remaining in the host system's interconnection queue are more likely to complete the interconnection study process. We agree with CAISO that this smaller pool of affected system interconnection customers will enable faster affected system studies due to a decreased volume of affected system interconnection customers and more realistic study assumptions.[2185] Accordingly, we find that beginning the affected system study process after the adopted trigger events provides greater certainty to interconnection customers regarding affected system network upgrade costs while ensuring a faster affected system study process. This is because the affected system transmission provider will be using more realistic study assumptions and studying a more realistic number of affected system interconnection customers, reducing the need for restudy.

1122. We find that notification to an affected system operator of a potential impact prior to receipt of cluster study results would be administratively burdensome and inefficient and could potentially slow the interconnection process because such notification would include numerous interconnection requests that ultimately do not reach commercial operation.[2186]

[2184] CAISO Initial Comments at 28; Idaho Power Initial Comments at 11; NextEra Initial Comments at 32.

[2185] CAISO Initial Comments at 29.

[2186] *Id.* at 28-29; Enel Initial Comments at 59; Idaho Power Initial Comments at 11; NextEra Initial Comments at 32.

1123. In eliminating the first two notification triggers, we recognize that the affected system study process will start later and, as a result, the interconnection customer could be required to execute, or request to be filed unexecuted, its LGIA before it has received its affected system study results and cost estimates for any affected system network upgrades. To avoid this result and in response to commenters' requests that transmission providers should be given the option to wait for affected system study results when conducting cluster studies,[2187] we modify the NOPR proposal and add a new section 11.2.1 to the *pro forma* LGIP. Under this section, if the interconnection customer does not receive its affected system study results pursuant to *pro forma* LGIP section 9.7, discussed below, before the deadline for LGIA execution, or the deadline to request that the LGIA be filed unexecuted, in its host system, the host transmission provider must, at the interconnection customer's request, delay the deadline for the interconnection customer to finalize its LGIA.[2188] The interconnection customer will have 30 calendar days after receipt of the affected system study report to execute the LGIA, or request that the LGIA be filed unexecuted.

1124. As noted above, we find that by adopting *pro forma* LGIP section 11.2.1, we ensure that interconnection customers have adequate time to evaluate their costs prior to committing to the cost estimates contained in an LGIA. Additionally, if the

[2187] PacifiCorp Initial Comments at 36-37; Pattern Energy Initial Comments at 25; Shell Initial Comments at 30-31.

[2188] Any interconnection customer that is not awaiting the results of an affected system study must proceed under the timelines set forth in *pro forma* LGIP section 11.1.

interconnection customer prefers to proceed to the execution of its LGIA, or request that the LGIA be filed unexecuted, before it has received its affected system study results, it may notify the host transmission provider of its intent to proceed with the execution of the LGIA, or request that the LGIA be filed unexecuted. If the host transmission provider determines that further delay to the LGIA execution date would cause a material impact on the cost or timing of an equal- or lower-queued interconnection customer, the transmission provider must notify the interconnection customer whose deadline to execute the LGIA, or request that the LGIA be filed unexecuted, is delayed of such impact and establish that the new deadline is 30 calendar days after such notice is provided.

1125. In response to ACE-NY's argument that no interconnection customer should be assigned affected system network upgrade costs after it executes its LGIA and/or after the interconnection customer has accepted its cost allocation in the class year process in NYISO,[2189] we decline to rule on specific transmission provider processes in this final rule. We note, however, that, under new *pro forma* LGIP section 11.2.1, interconnection customers may negotiate LGIA execution to await an affected system study report for greater certainty at the time of LGIA execution, or requesting the LGIA to be filed unexecuted, if that further delay to the LGIA execution date would not cause a material impact on the cost or timing of an equal- or lower-queued interconnection customer.

[2189] ACE-NY Initial Comments at 9.

1126. We decline to require the affected system transmission provider to provide affected system study results before the facilities study phase, as asserted by Enel and Shell,[2190] because such a requirement would necessitate that the affected system transmission provider would have to begin such studies before any interconnection customers withdraw from the interconnection queue and would therefore involve the study of numerous interconnection requests that do not eventually proceed to commercial operation, resulting in additional restudies and delays.

1127. In response to Tri-State's argument that proposed *pro forma* LGIP section 3.6.1 needs to clarify to whom notice is to be directed,[2191] we note the language in *pro forma* LGIP section 3.6.1 beginning with "Transmission Provider must notify Affected System Operator of a potential Affected System impact." If Tri-State is asking to whom the affected system transmission provider should respond in writing regarding whether it intends to conduct an affected system study, it should respond to the transmission provider who notified the affected system operator of a potential affected system impact.

1128. We adopt Pacific Northwest Utilities' requested clarification and agree with Puget Sound that, provided that transmission providers properly notify a non-public utility affected system operator within 10 business days under proposed *pro forma* LGIP section

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[2190] *See* Enel Initial Comments at 58; Shell Initial Comments at 30-31.

[2191] Tri-State Initial Comments at 28.

3.6.1, such steps are sufficient to demonstrate that the transmission provider has met its obligations under that section.[2192]

1129. We agree with Interwest and Invenergy that the interconnection customer should be permitted to delay posting security and funding for network upgrades under its LGIA until affected system study results are received in certain situations.[2193] Specifically, an interconnection customer is not required to post security for and fund network upgrades pursuant to an LGIA if the deadline for LGIA execution, or to request that the LGIA be filed unexecuted, is delayed under *pro forma* LGIP section 11.2.1. We agree with Interwest that this would reduce an affected system interconnection customer's risk of incurring affected system network upgrade costs after LGIA execution. However, if the interconnection customer chooses to proceed to execute an LGIA, or request that the LGIA be filed unexecuted, it will be responsible for posting security and funding network upgrades as per the schedule in its LGIA, regardless of whether it has received affected system study results.

1130. We disagree with commenters that a transmission provider's obligation to notify a potential affected system operator of an impact in 10 business days is unrealistic or problematic.[2194] As we are eliminating two trigger events, the host transmission provider

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[2192] Pacific Northwest Utilities Initial Comments at 17; Puget Sound Initial Comments at 8.

[2193] Interwest Reply Comments at 18; Invenergy Initial Comments at 43.

[2194] CAISO Initial Comments at 27; Duke Southeast Utilities Initial Comments at 12; PacifiCorp Initial Comments at 36; PG&E Reply Comments at 5.

now has the obligation to notify the affected system operator of a potential impact to the affected system following the completion of the cluster study or restudy, which we find provides a clear timeline contrary to PacifiCorp's claims. Furthermore, we do not find any convincing evidence that a host transmission provider will be unable to provide a notification to an affected system operator of potential impacts within 10 business days and note that this timeline is supported by commenters.[2195]

1131. However, regarding comments that the affected system operator's obligation to respond in 15 business days is insufficient,[2196] particularly when numerous potential affected system impacts are identified in a single cluster study, as stated above, we extend the affected system operator's response obligation time period from 15 business days to 20 business days to provide the affected system operator with additional time to consider whether to study these potential affected system impacts on its transmission system, consistent with Duke Southeast Utilities' suggestion.[2197] We find these timelines necessary to ensure timely processing of the affected system study process and to provide certainty to the interconnection customer regarding the processing of the affected system study.

[2195] *See* AEP Initial Comments at 31; Pine Gate Initial Comments at 42.

[2196] Bonneville Initial Comments at 18; CAISO Initial Comments at 27; Duke Southeast Utilities Initial Comments at 12; PG&E Reply Comments at 5; WAPA Initial Comments at 11-12.

[2197] *See* Duke Southeast Utilities Initial Comments at 12.

(c) Affected System Scoping Meeting (*Pro Forma* LGIP Section 3.6.2) and Affected System Study Procedures (*Pro Forma* LGIP Section 9.7)

1132. We decline to adopt the proposed requirement in *pro forma* LGIP section 3.6.2 that affected system transmission providers must hold an affected system scoping meeting within seven business days after providing written notification that it intends to conduct an affected system study. We agree with commenters' concerns that the difficulties associated with holding an affected system scoping meeting within the proposed time frame outweigh its potential benefits.[2198] We also agree with WAPA that a meeting after the affected system study is completed would be more beneficial than an affected system scoping meeting.

1133. We adopt, with modifications, the proposed affected system study procedures set forth in *pro forma* LGIP section 9.6, now section 9.7. In particular, we modify the NOPR proposal to explicitly require clustering of affected system interconnection customers for study purposes where multiple interconnection requests that are part of a single cluster in the host system's cluster study process cause the need for an affected system study. We find that clustered affected system studies will, consistent with the requirement to use a first-ready, first-served cluster study process, improve administrative efficiency in the affected system study process and reduce administrative burden on the affected system

[2198] Bonneville Initial Comments at 18-19; CAISO Initial Comments at 28; Dominion Initial Comments at 38; MISO Initial Comments at 86; WAPA Initial Comments at 12.

transmission provider, thereby promoting overall efficiency in the interconnection process. We agree with commenters that serial affected system studies would place an additional burden on transmission providers to study affected system impacts and would further slow the interconnection process.[2199] We, therefore, believe that mandating clustering of affected system studies will not place an additional unnecessary burden on transmission providers, no matter their size; rather, it should reduce such burdens as compared to multiple serial studies and restudies.

1134. We further modify proposed *pro forma* LGIP section 9.7, to require the affected system transmission provider to complete the affected system study and provide the affected system interconnection customer with affected system study results within 150 calendar days after receipt of the affected system study agreement, rather than the proposed 90 calendar days. We agree with commenters that explain that 90 calendar days may not be adequate time to complete an affected system study,[2200] aligning with our discussion of the potential for affected system transmission providers to conduct a facilities study under proposed *pro forma* LGIP section 9.6 below. In recognition of that, we extend the proposed maximum time frame to complete an affected system study from the NOPR's proposed 90 calendar days to 150 calendar days. This extension addresses

[2199] AECI Initial Comments at 6-7; Indicated PJM TOs Initial Comments at 47; NextEra Reply Comments at 4; North Carolina Commission and Staff Initial Comments at 24-25 (citing Gajda Aff. ¶¶ 21-22, 27); SPP Initial Comments at 15-16.

[2200] AEP Initial Comments at 31; Enel Initial Comments at 65; WAPA Initial Comments at 13.

Bonneville's concern that the proposed schedule to complete an affected system study may have included a due date in excess of the 90-calendar day timeline.

1135. We also modify *pro forma* LGIP section 9.7, which, as proposed, required the affected system transmission provider to notify the affected system interconnection customer that an affected system study will be late, to add a requirement for the affected system transmission provider to notify the host transmission provider that the affected system transmission provider will be unable to timely complete the affected system study.

1136. We adopt Tri-State's request to add the phrase "and deposit" to *pro forma* LGIP section 9.7, such that the affected system transmission provider must provide the affected system study report to the affected system interconnection customer within 150 calendar days after the receipt of the affected system study agreement and deposit. We find this addition is needed to clarify the affected system interconnection customer's obligation to provide an affected system study deposit, especially if an affected system interconnection customer loses its affected system queue position, discussed below, for failure to provide the required deposit under *pro forma* LGIP section 9.5. We also add to *pro forma* LGIP section 9.7 a requirement for the affected system transmission provider to provide the affected system study report to the host transmission provider at the same time it provides the report to the affected system interconnection customer. We find that this will enhance transparency in the interconnection study process.

1137. In response to MISO's request for clarification that the affected system study clock commences only after all necessary data has been provided, we clarify that,

because an affected system interconnection customer has already submitted all required data to the host transmission provider, and the host transmission provider has verified that the data submitted is adequate and has conducted at least one interconnection study, it is highly unlikely that there will be any instances of requiring clarification or further data from interconnection customers. Thus, under the modified affected system study procedures, the data regarding interconnection requests given to the affected system transmission provider should be complete, requiring no delay or requests for further data. Nevertheless, we note that the affected system interconnection customer is required, under *pro forma* LGIP section 9.5, to provide all required technical data when it delivers the affected system study agreement. As discussed below, the clock for the affected system transmission provider to complete its affected system study begins after the receipt of the executed affected system study agreement and study deposit, which would include the receipt of all required technical data from the affected system interconnection customer.

(d) Affected System Queue Position (*Pro Forma* LGIP Section 9.3)

1138. We adopt, with modification, the NOPR proposal to add section 9.2, now section 9.3, titled "Affected System Queue Position," to the *pro forma* LGIP. Specifically, we adopt the first-ready, first-served concept, as proposed in the NOPR,[2201]

[2201] We note that several commenters support the proposed first-ready, first-served concept under proposed *pro forma* LGIP section 9.2. *See* Alliant Energy Initial Comments at 7; MISO Initial Comments at 11-12; NextEra Initial Comments at 33; OMS Initial Comments at 17.

along with the affected system relative queue priority proposal. Consequently, the interconnection requests of affected system interconnection customers that have executed an affected system study agreement will be higher-queued than the interconnection requests of those host system interconnection customers that have not yet received their cluster study results, and lower-queued than those interconnection customers that have already received their cluster study results. We also add clarifying language to *pro forma* LGIP section 9.3 to explain that, although queue position is determined based on the date of affected system study agreement execution, all affected system interconnection requests studied within the same affected system cluster will be equally queued.

1139. The affected system interconnection customer's affected system queue position is for identification of affected system network upgrades along with the affected system transmission provider's own interconnection customers. Specifically, the affected system queue position determines the order in which the affected system transmission provider will study the affected system interconnection customers and its own interconnection customers and thus impacts which network upgrades may be identified as necessary and assigned to interconnection customers, whether its own or affected system interconnection customers.

1140. As an example, if a transmission provider has two cluster studies of its own interconnection customers—cluster study 1 for which the transmission provider is conducting the facilities studies and cluster study 2 for which the transmission provider is conducting the cluster study—cluster study 1 would be higher-queued than cluster study 2. If that transmission provider receives notice from a neighboring transmission provider

of interconnection requests that may impact its transmission system (i.e., affected system interconnection customers), the transmission provider may decide to study those affected system interconnection customers to determine if any network upgrades are required to mitigate constraints caused by those affected system interconnection customers. Once those affected system interconnection customers have executed their affected system study agreements, the transmission provider must assign them an affected system queue position, which will be higher than any cluster study of its own interconnection customers that have not received their cluster study results. In this example, the cluster study 1 interconnection customers would be higher-queued than the cluster of affected system interconnection customers because the cluster study 1 interconnection customers would have already received their cluster study results and decided to proceed with their interconnection requests, and cluster study 2 interconnection customers would be lower-queued than the cluster of affected system interconnection customers because they would not have received their cluster study results and thus are more likely to withdraw.

1141. We find that establishing the affected system queue position based on the execution of the affected system study agreement is appropriate because, at that point, the affected system interconnection customer has demonstrated its intent to proceed with its interconnection request by executing the agreement and providing a study deposit to the affected system transmission provider as well as receiving its cluster study report on its host system and deciding to proceed with its interconnection request. Furthermore, allowing these affected system interconnection customers to be higher-queued than any of its own interconnection customers that have not received their cluster study results is

appropriate because those interconnection customers have not yet received any network upgrade estimates. Thus, its own interconnection customers have not yet demonstrated their intention to proceed to the facilities study.

1142. We agree with commenters that establishing queue priority in an affected system transmission provider's interconnection queue based on when an interconnection request is received by the host transmission provider is problematic.[2202] In part for this reason, we are adopting the host system's cluster study results and execution of the affected system study agreement as reference points for queue priority[2203] because these points occur after the interconnection customer has made demonstrations to indicate intent to progress through the interconnection process.

1143. We disagree with NextEra that the NOPR proposal's affected system queue priority construct, which we adopt herein, will lead to a race among interconnection customers to be first or last to sign an affected system study agreement. NextEra's concern may occur under a serial affected system study process, but, as explained above, we require clustering of affected system studies. Studying affected system interconnection requests in clusters mitigates the risk of a race to execute affected system study agreements, as affected system interconnection customers in the same affected system cluster will be equally queued regardless of when they execute their affected system study agreement, if it is within the appropriate window for affected system study

[2202] EDF Renewables Initial Comments at 11; MISO Initial Comments at 11, 87.

[2203] *See* NOPR, 179 FERC ¶ 61,194 at P 189.

agreement execution. We find this to be a just and reasonable queue priority construct for affected system studies.

1144. We decline to adopt EDF Renewables' suggestion that the affected system transmission provider be required to establish queue priority between the host and affected systems based on the interconnection customer having achieved a certain stage in the host system's study process, rather than the date the interconnection customer submits an interconnection request. We clarify that we neither propose to, nor do we adopt a proposal to, base relative affected system queue priority on the date an interconnection customer submits its interconnection request.[2204]

1145. We clarify, in response to Idaho Power's request, that the affected system study process adopted in this final rule is required for all transmission providers, regardless of preexisting use of the first-ready, first-served cluster study process.

1146. We clarify, in response to APPA-LPPC, that establishing the affected system queue priority is for identifying the affected system network upgrades needed to mitigate constraints on the affected system.[2205] This process will proceed in parallel with the host transmission provider's study process and should not result in delays to the interconnection customer. As discussed above, we allow interconnection customers to

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[2204] *See* NOPR, 179 FERC ¶ 61,194 at P 189 (providing that the affected system transmission provider would assign the affected system interconnection customer a queue position in its queue according to when the affected system interconnection customer executes an affected system study agreement rather than when the affected system interconnection customer entered its host transmission provider's queue).

[2205] APPA-LPPC Initial Comments at 26.

delay execution of their LGIAs, or request that the LGIA be filed unexecuted, if they have not received their affected system study results; however, based on the reforms we adopt in this final rule, that should be the exception and not the rule. Thus, we find that the affected system queue position is merely intended to ensure that affected system interconnection customers are assigned the appropriate network upgrade costs according to the Commission's interconnection pricing policy, and not as an indicator that interconnection customers become part of two separate interconnection queues.

1147. With respect to requests for clarification regarding proposed *pro forma* LGIP section 9.2 and how the first-ready, first-served queue priority approach interacts with cluster studies,[2206] we clarify that all affected system interconnection customers in the same cluster on the affected system will have equal queue priority in the affected system transmission provider's interconnection queue, which is consistent with how the first-ready, first-served approach interacts with cluster studies for interconnection customers on the transmission provider's transmission system when it is acting as a host system. This means that the affected system interconnection customers within a cluster have equal queue priority and that queue priority will be relative to the affected system transmission provider's own interconnection customers. The affected system transmission provider's own interconnection customers that already received their cluster study results when an affected system interconnection customer or cluster of affected system interconnection customers execute an affected system study agreement will be

[2206] *Id.*; Idaho Power Initial Comments at 11; NextEra Initial Comments at 33.

higher-queued than that affected system interconnection customer. Any of the affected system transmission provider's own interconnection customers that receive their cluster study results after the affected system interconnection customer or cluster of affected system interconnection customers execute their affected system study agreement will be lower-queued than that affected system interconnection customer or cluster of affected system interconnection customers. We clarify in response to APPA-LPPC that a transmission provider will assign the costs of network upgrades required on its transmission system to interconnection customers in its host cluster study process and affected system interconnection customers, also studied in their own cluster, based on their relative queue priority and in accordance with the proportional impact method as described in *pro forma* LGIP section 4.2.3, and as discussed further in the next section.[2207]

1148. With respect to Bonneville's request for clarification, we clarify that an affected system interconnection customer will lose its affected system queue position if the affected system interconnection customer fails to: (1) execute the affected system study agreement or request it be filed unexecuted; (2) execute the affected system facilities construction agreement or request it be filed unexecuted; (3) provide the affected system study deposit; or (4) pay undisputed affected system study true-up costs in a timely manner.

[2207] APPA-LPPC Initial Comments at 26.

(e) Affected System Cost Allocation (*Pro Forma* LGIP Section 9.9)

1149. We also adopt the NOPR proposal in *pro forma* LGIP section 9.8, now *pro forma* LGIP section 9.9, titled "Affected System Cost Allocation," to allocate affected system network upgrade costs using a proportional impact method, in accordance with *pro forma* LGIP section 4.2.1(1)(b).

1150. We agree with SEIA that using a proportional impact method will reduce individual affected system network upgrade costs and reduce the likelihood of cascading withdrawals, consistent with our discussion above on the use of the proportional impact method for the allocation of network upgrade costs in a cluster on the host system.

1151. We disagree with commenters that argue that the Commission should provide for penalty-free withdrawal from the host system's interconnection queue if affected system study results increase an interconnection customer's costs by more than 25% or some other threshold compared to costs allocated by the host transmission provider.[2208] First, we find that the final rule's requirement that affected system transmission providers use ERIS modeling standard to conduct affected system studies should reduce the number and total cost of affected system network upgrades assigned to affected system interconnection customers, which will reduce instances of "sticker shock" from affected system network upgrades.[2209] Second, as discussed above, any interconnection customers

[2208] Invenergy Initial Comments at 43-44; Shell Initial Comments at 31.

[2209] *See infra* Section III.B.2.d.iii.

in a cluster that are not waiting for affected system study results must proceed with the finalization of their LGIAs, pursuant to *pro forma* LGIP section 11.1. Thus, we find that it would create sufficient uncertainty to allow an interconnection customer to withdraw penalty-free when it receives its affected system study results if there is a 25% increase in costs, which may occur after other interconnection customers in the same cluster have finalized their LGIAs. We note that interconnection customers inherently assume some risk. Accordingly, we decline to explicitly extend penalty-free withdrawal to include increases in affected system network upgrade costs beyond a certain threshold.

1152. In response to NV Energy's assertion that use of the proportional impact method may lead to restudies when a higher-queued affected system interconnection customer withdraws its interconnection request, we note that potential outcomes of withdrawal are restudy and the reallocation of costs, regardless of the cost allocation methodology used.[2210] We also note that, as described above, transmission providers may not need to perform a study if, in their engineering judgment, the network upgrades assigned to the withdrawing interconnection customer either are not needed or are easily reassigned to a remaining interconnection customer. Thus, restudies under the new interconnection process due to interconnection request withdrawals should be relatively less frequent than under existing processes.

[2210] NV Energy Initial Comments at 11-12.

(f) <u>Information Sharing Among Transmission Providers (*Pro Forma* LGIP Section 3.6.3)</u>

1153. We decline to adopt proposed section 3.6.3 of the *pro forma* LGIP, which would have required a transmission provider to provide data on a monthly basis, or more frequently as needed, to any affected system operators regarding the amount and location of proposed generation in the transmission provider's interconnection queue, as well as updated information about the transmission provider's transmission system.[2211] We agree with commenters' arguments that the information sharing requirement is duplicative of what is available on OASIS and recognize that such a requirement may be overly burdensome.[2212] The OASIS postings provide transparency regarding the host transmission provider's interconnection queue information. Further, transmission providers are required to notify neighboring transmission providers of potential impacts on their systems per section 3.6.1 of the *pro forma* LGIP, as described above.

(g) <u>Affected System Study Agreement (*Pro Forma* LGIP Section 9.4) and Execution Thereof (*Pro Forma* LGIP Section 9.5)</u>

1154. With regard to tendering of the affected system study agreement to the affected system interconnection customer, we modify proposed *pro forma* LGIP section 9.3, now *pro forma* LGIP section 9.4, to require that the transmission provider provide the affected system study agreement within 10 business days of sharing the schedule for the study

[2211] Accordingly, we do not address comments on this section.

[2212] Bonneville Initial Comments at 19; Dominion Initial Comments at 38.

with the affected system interconnection customer(s), per *pro forma* LGIP section 9.2, rather than within five business days, as proposed. We agree with commenters that five business days is not enough time to prepare what could be numerous affected system study agreements in the event a number of interconnection customers in a large cluster on a neighboring transmission system impact the affected system transmission provider's transmission system.

1155. Consistent with our decision—discussed above—to not adopt the proposal to require affected system transmission providers to convene a scoping meeting with affected system interconnection customers, we remove references to such a meeting in *pro forma* LGIP section 9.4. Accordingly, we modify the NOPR proposal requiring the affected system operator to provide a non-binding good faith estimate of the cost and time frame for completing an affected system study from 15 business days after the affected system scoping meeting to 20 business days from the date that the affected system operator responded in writing to the host transmission provider that it intends to conduct an affected system study, pursuant to section 3.6.1 of the *pro forma* LGIP, and we also move this requirement to section 9.2 of the *pro forma* LGIP. The time taken to tender an affected system study agreement will also be measured from that date. We believe these changes will align the study timeline to the lack of an affected system scoping meeting.

1156. Accordingly, we modify proposed *pro forma* LGIP section 9.4 so that, after the affected system transmission provider responds with its intent to conduct an affected system study, the affected system transmission provider has 10 business days to tender an

affected system study agreement from the date of the affected system transmission provider sharing the schedule for the study. Again, these changes align the affected system study process timeline with the modification to remove the affected system scoping meeting.

1157. We further modify proposed *pro forma* LGIP section 9.4 to include a true-up of the affected system study deposit and actual cost of the affected system study. The difference between these amounts must be detailed in an invoice and paid by or refunded to the affected system interconnection customer within 30 calendar days of the receipt of such invoice. An affected system interconnection customer's failure to pay the difference between these amounts will result in loss of that affected system interconnection customer's affected system queue position. We find these modifications necessary to effectuate actual payment of affected system study costs and to outline the consequences for failure to do so.

1158. With regard to execution of the affected system study agreement, we adopt, with modification, the NOPR proposal to add section 9.5 to the *pro forma* LGIP regarding the timing of the execution of the affected system study agreement. As adopted, *pro forma* LGIP section 9.5 states that the affected system interconnection customer has 10 business days from the date of receipt of the affected system study agreement to execute and deliver it to the affected system transmission provider. *Pro forma* LGIP section 9.5 also provides that, if the affected system interconnection customer does not provide all required technical data when it delivers the affected system study agreement, the affected system transmission provider shall notify the affected system interconnection customer of

the deficiency within five business days of the receipt of the affected system study agreement, and the affected system interconnection customer has 10 business days to cure the deficiency after receipt of such notice, provided that the deficiency does not include failure to deliver the executed affected system study agreement or deposit.

1159. In the same vein, we modify proposed section 9.4 of the *pro forma* LGIP to require the affected system transmission provider to notify the host transmission provider of the affected system interconnection customer's breach of its obligations under this section, should such breach occur. We find that, absent such notification, the host transmission provider may be unaware of such a breach.

(h) <u>Scope of Affected System Study (*Pro Forma* LGIP Section 9.6)</u>

1160. We adopt, with modification, the NOPR proposal in *pro forma* LGIP section 9.5, now *pro forma* LGIP section 9.6, regarding the scope of the affected system study. The affected system study will consider the base case as well as all higher-queued generating facilities on the affected system transmission provider's transmission system and will consist of a power flow, stability, and short circuit analysis. The affected system study will provide a list of affected system network upgrades that are required because of the affected system interconnection customer's proposed interconnection, a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct. We find that these requirements will ensure that the affected system study will identify affected system network upgrades that are necessary to mitigate the impacts of the affected system interconnection customer's proposed generating facility on the

affected system while providing the affected system interconnection customer with estimated costs and a timeline to construct necessary network upgrades.

1161. In response to APPA-LPPC, Duke Southeast Utilities, Enel, and Pattern Energy, we modify the NOPR proposal and clarify that *pro forma* LGIP section 9.6 does not preclude affected system transmission providers from conducting facilities studies or other relevant studies when conducting affected system studies. The affected system study may consist of a system impact study, a facilities study, or a combination of a system impact and facilities study.

1162. To address commenters' criticism that the NOPR proposal was ambiguous with respect to whether a facilities study is specifically contemplated as part of the affected system study process,[2213] we clarify that it is. We agree with commenters that an affected system facilities study could provide more refined cost estimates and construction timelines to better apprise the affected system interconnection customer of expected affected system network upgrade costs and timing, thereby improving interconnection process efficiency.[2214] We note that the study requirements for the affected system study under *pro forma* LGIP section 9.6 that we proposed in the NOPR, and adopt in this final rule, require the affected system transmission provider to produce the same information that a facilities study would produce; specifically, the affected system transmission

[2213] APPA-LPPC Initial Comments at 26; Duke Southeast Utilities Initial Comments at 15.

[2214] Enel Initial Comments at 65; LADWP Initial Comments at 4; NV Energy Initial Comments at 11; Pattern Energy Initial Comments at 24-25.

provider must provide a list of facilities that are required as a result of an affected system interconnection customer's proposed interconnection, a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct. Nevertheless, for further clarity, we modify proposed *pro forma* LGIP section 9.6 to indicate that the affected system study may consist of a system impact study, a facilities study, or some combination thereof. We note that we have modified the proposal to provide more time to the transmission provider to conduct such studies that they deem necessary, as discussed above.

1163. In response to Duke Southeast Utilities' request for clarification that affected system transmission providers conduct a series of two affected system studies, we reiterate that nothing precludes an affected system transmission provider from conducting an affected system facilities study following an affected system impact study, just as nothing precludes affected system transmission providers from conducting a combined version of such studies, and we believe we have provided adequate time for transmission providers to do so.

1164. We find out of scope Shell's request for inclusion of further information on local transmission planning from neighboring public utility transmission providers in the affected system study results.

(i) Meeting with Transmission Provider (*Pro Forma* LGIP Section 9.8) and Affected System Facilities Construction Agreement (*Pro Forma* LGIP Section 9.10)

1165. We adopt proposed section 9.9, now section 9.10, of the *pro forma* LGIP, with modifications. Specifically, we adopt the requirement for an affected system transmission provider to tender to the affected system interconnection customer an affected system facilities construction agreement within 30 calendar days of providing the affected system study report. We modify this section to require the affected system transmission provider to provide 10 business days—rather than five business days, as proposed—after receipt of the affected system facilities construction agreement for the affected system interconnection customer to execute the agreement or have the affected system transmission provider file it unexecuted with the Commission. While no comments were filed in opposition to the five business days to notify the affected system transmission provider of the affected system interconnection customer's intent to execute the agreement or request it to be filed unexecuted, as proposed in the NOPR, we believe that 10 business days gives the affected system interconnection customer a more appropriate length of time to review the facilities construction agreement and the timelines and costs contained therein to make a reasoned decision as to whether to execute the agreement or request that it be filed unexecuted with the Commission.

1166. Further, we find that it is appropriate to allow the interconnection customer to request that the affected system facilities construction agreement be filed unexecuted at the Commission. Similar to an interconnection customer's ability pursuant to *pro forma*

LGIP section 11.3 to request the unexecuted filing of its LGIA, the ability to request the affected system facilities construction agreement be filed unexecuted allows an affected system interconnection customer to dispute provisions of the affected system facilities construction agreement before the Commission.[2215] Because (1) the existing *pro forma* LGIP section 11.3 permits the interconnection customer to request the transmission provider to file the LGIA unexecuted, (2) we base the affected system facilities construction agreement on the *pro forma* LGIA, and (3) the affected system facilities construction agreement is like a service agreement,[2216] it is appropriate to include a similar provision. We further find that an affected system interconnection customer may be in a disadvantageous position to negotiate the terms of an affected system facilities construction agreement, as this agreement is between the affected system interconnection customer and a transmission provider with which it does not directly connect. Accordingly, to encourage good faith and fair dealings between the parties and to avoid

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[2215] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 233 (stating that, if agreement negotiations are at an impasse, the interconnection customer could either request termination of negotiations and request submission of the unexecuted agreement to the Commission or initiate dispute resolution procedures).

[2216] *See Revised Publ. Util. Filing Requirements*, Order No. 2001, 99 FERC ¶ 61,107, at PP 196, 200, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334, *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 120 FERC ¶ 61,270, *order on reh'g and clarification*, Order No. 2001-H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements*, Order No. 2001-I, 125 FERC ¶ 61,103 (2008); *see also* Order No. 2003, 104 FERC ¶ 61,103 at PP 913-915.

the addition of potentially discriminatory terms or conditions to an affected system facilities construction agreement, we allow an affected system interconnection customer to request that an affected system facilities construction agreement be filed unexecuted before the Commission.

1167. We disagree with commenters' assertions that 30 calendar days may be an inadequate length of time to tender an affected system facilities construction agreement or that considerable time is needed to draft such an agreement.[2217] This is the same period of time by which the transmission provider must tender a draft LGIA to the interconnection customer, the timeline of which is set forth in the existing *pro forma* LGIP.[2218] We believe these timelines should be consistent because these agreements include similar provisions and similar requirements and the record does not persuade us otherwise.

1168. We disagree with Idaho Power's suggestion that the affected system transmission provider should tender an affected system facilities construction agreement within 60 calendar days of the interconnection customer executing a facilities study agreement with the host transmission provider because, as the host system and affected system study processes are separate, though overlapping and interrelated, it is more administratively feasible to tie affected system study process deadlines to affected system study process

[2217] *See* Duke Southeast Utilities Initial Comments at 15-16; Idaho Power Initial Comments at 11; MISO Initial Comments at 91-92; WAPA Initial Comments at 13.

[2218] *Pro forma* LGIP section 11.1.

events. In response to Idaho Power's suggestion that the affected system transmission provider should tender an affected system facilities construction agreement within 30 calendar days of providing the affected system study results to the affected system interconnection customer if the affected system study is performed during the facilities study on the host transmission provider's system,[2219] we note that, as proposed in the NOPR, the affected system facilities construction agreement tender deadline is within 30 calendar days of the tendering of the affected system study report without any additional caveats or conditions. This tender timeline is, however, not directly linked to the host transmission provider's study process.

1169. We also adopt the NOPR proposal to add section 9.7, now section 9.8, to the *pro forma* LGIP. Section 9.8 of the *pro forma* LGIP, titled "Meeting with Transmission Provider," requires the affected system transmission provider and the affected system interconnection customer to meet within 10 business days of the affected system transmission provider tendering the affected system study report to the affected system interconnection customer. We find that such a meeting between the affected system transmission provider and affected system interconnection customer will facilitate transparency and meaningful communication in the affected system study process. We note that WAPA stated that a meeting after the affected system study report is tendered would be more beneficial than an affected system scoping meeting. We agree with WAPA and find that no changes to this section are necessary.

[2219] Idaho Power Initial Comments at 11.

(j) Restudy Period (*Pro Forma* LGIP Section 9.11)

1170. We adopt the NOPR proposal in section 9.10, now section 9.11, of the *pro forma* LGIP to include a maximum 60-calendar day restudy period for any affected system restudies. We find that 60 calendar days are adequate to complete an affected system restudy. We disagree that affected system restudies are as complex as host system restudies, as affected system studies will likely involve fewer interconnection requests than cluster studies on the host system. Additionally, as discussed further below, we find that standardization of affected system study assumptions through ERIS modeling criteria will further simplify both affected system studies and restudies. Thus, we find it just and reasonable to adopt a 60-calendar day affected system restudy period.

1171. In addition to the 60-calendar day restudy period, we adopt a 30-calendar day notification requirement for the affected system transmission provider to notify the affected system interconnection customer of the need for affected system restudy upon discovery of such need in *pro forma* LGIP section 9.11. We find such a notification requirement to be consistent with restudy notification on the host system, and we find such notification necessary to continue a timely affected system study process. Accordingly, we find such a notification period to be just and reasonable.

(k) Coordination Between Host Transmission Provider and Affected System Transmission Provider

1172. In response to multiple commenters' assertions that, for efficiency reasons, host transmission providers should be required to coordinate affected system study activities

with affected system transmission providers rather than individual interconnection customers,[2220] or that flexibility should be afforded in terms of the parties to the affected system study agreement and the affected system facilities construction agreement,[2221] the Commission is not persuaded that any potential efficiencies of such coordination outweigh the burdens that may be placed on host transmission providers, and we decline to require it in this final rule. We note that, in many cases, the affected system operator may be a non-public utility transmission provider, which would limit the usefulness of such a requirement. However, we encourage any such voluntary coordination between transmission providers who share transmission system seams and whose interconnection customers frequently impact each other's systems. We also note that, as NextEra suggests, such transmission providers may file seams agreements under FPA section 205.[2222]

1173. In response to Indicated PJM TOs' argument that affected system studies should be integrated into the cluster study process, we do not have a record to support such a requirement in the final rule. Integrating affected system interconnection customers into a cluster that is already proceeding through the study process could meaningfully change network upgrade cost estimates which could, in turn, create new interconnection request withdrawals, leading to restudies and delays. Maintaining the clusters as-is and placing

[2220] Enel Initial Comments at 60-61; Shell Initial Comments at 30.

[2221] PPL Initial Comments at 20.

[2222] NextEra Reply Comments at 5.

the affected system interconnection customers in a lower queue position than any interconnection customers that have received cost estimates will ensure this situation does not happen.

1174. In response to APS' request for clarification on how the proposed affected system study process correlates to the host system's studies and aligns with the host system's requirements,[2223] we explain that the affected system study is predicated on the completion of a cluster study in the host transmission provider's interconnection queue. Relative queue position for the affected system study is also determined based on an interconnection customer's completion of the host system cluster study. While the host transmission provider will likely complete its facilities study prior to an affected system transmission provider's completion of an affected system study, we add a requirement for host transmission providers with interconnection customers that have not yet received their affected system study results to delay the LGIA execution (or unexecuted filing) deadline for those interconnection customers. An interconnection customer's failure to satisfy its obligations under the *pro forma* LGIP, including coordination with the affected system transmission provider, where applicable, will result in the loss of the interconnection customer's affected system queue position.

[2223] APS Initial Comments at 19-20.

(l) Non-Public Utility Requests

1175. We reject requests to impose firm deadlines and requirements that prevent non-public utility transmission providers from interfering with jurisdictional interconnection agreements because we do not have the jurisdiction to do so.[2224]

1176. In response to concerns regarding a transmission provider's liability for delays or inaction by non-public utility transmission providers,[2225] we clarify that transmission providers will not face consequences for the inaction of a non-public utility transmission provider, as long as the transmission providers fulfill their obligations as outlined in their LGIPs. For example, under the *pro forma* LGIP affected system process, a transmission provider would satisfy its obligation to a non-public utility affected system operator by timely notifying it of an affected system impact per *pro forma* LGIP section 3.6.1.

(m) Miscellaneous

1177. We do not address the comments of North Carolina Commission and Staff and EDF Renewables that interregional transmission planning is a way to address affected system impacts because these comments are beyond the scope of this proceeding, which is limited to generator interconnection.

1178. In response to Eversource's and NYTOs' requests for clarification that affected system study process reforms would not apply to intra-RTO/ISO system upgrades or

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[2224] Invenergy Initial Comments at 43; Invenergy Reply Comments at 9; Interwest Reply Comments at 18.

[2225] EEI Initial Comments at 19; NextEra Initial Comments at 34; Pacific Northwest Utilities Initial Comments at 15-16; Xcel Initial Comments at 39.

would not apply to neighboring transmission owners within a single RTO/ISO,[2226] we clarify that, in RTO/ISO regions, the RTO/ISO serves as the transmission provider for affected system study purposes, and the RTO/ISO footprint as the affected system, and thus intra-RTO/ISO considerations do not apply in this context and are beyond the scope of this final rule.

1179. We disagree with Invenergy's argument that affected system study process reforms should apply to all pending interconnection requests and active studies.[2227] While we adopt a transition approach for serial and cluster study processes in the final rule, as explained above, we did not propose a similar transition approach with respect to affected system studies in the NOPR. Without consistency between transition processes as they pertain to neighboring transmission providers and implicate the affected system study process, it would be practically infeasible to apply the affected system study process reforms to all pending interconnection requests and active studies as Invenergy suggests. Accordingly, we decline to apply the affected system study process reforms adopted in this final rule to any pending interconnection requests and active studies.

1180. In response to CREA and NewSun's request for clarification that a QF interconnection customer has the option to opt into use of the Commission's interconnection procedures in cases where the interconnection requires studies or network

[2226] *See also* AEP Initial Comments at 32-33 (highlighting four different types of affected system scenarios and contending that the Commission conflates them).

[2227] Invenergy Initial Comments at 41.

upgrades on affected systems,[2228] we decline to implement a jurisdictional toggle option for an interconnection customer. Longstanding Commission precedent indicates when a QF's interconnection is subject to state jurisdiction or Commission jurisdiction.[2229] Nothing in this final rule is intended to revise the Commission's approach under PURPA. Requiring affected system studies does not change the sale of a QF's output, which is the foundation of the Commission's interconnection analysis under PURPA.[2230] To the extent that affected system studies are required due to a QF interconnection, the Commission will address such filings upon their receipt.

[2228] CREA and NewSun Initial Comments at 86-88.

[2229] Order No. 2003, 104 FERC ¶ 61,103 at PP 813-814 (finding that, when an electric utility purchases a QF's total output, the state exercises jurisdiction over the interconnection and allocation of interconnection costs, while the presence of any output sold to a third party yields Commission jurisdiction); *Fla. Power & Light Co.*, 133 FERC ¶ 61,121, at PP 19-23 (2010). *See also* 18 CFR 202.303, 202.306 (2022); *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 85 FR 67094 (Oct. 21, 2020), 172 FERC ¶ 61,247, at P 98 (2020), *corrected*, 85 FR 68540 (Oct. 29, 2020) (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 813-815; Order No. 2006, 111 FERC ¶ 61,220 at PP 516-518; Order No. 845, 163 FERC ¶ 61,043) (stating that nothing in the final rule revises the Commission's jurisdictional approach to interconnections of QFs that participate in distributed energy resource aggregations).

[2230] Order No. 2003, 104 FERC ¶ 61,103 at PP 813-814.

c. Affected System *Pro Forma* Agreements

i. Need for Reform

(a) NOPR Proposal

1181. In the NOPR, the Commission expressed concern that the lack of *pro forma* agreements for affected system studies and the construction of network upgrades on affected systems was hindering the efficiency of the generator interconnection process through increased litigation over such agreements and allowed for potential unduly discriminatory behavior against interconnection customers whose interconnection requests necessitate affected system network upgrades.[2231] Noting a recent increase in affected system-related disputes, the Commission preliminarily found it unjust and unreasonable to leave affected system agreements wholly up to individual negotiations and proposed standardized *pro forma* affected system agreements that minimize the likelihood for such disputes by (1) stipulating how to study the impact of interconnecting generating facilities on an affected system to identify network upgrades needed to accommodate the interconnection request and (2) standardizing the affected system facilities construction agreement to set the terms and conditions for the construction of those network upgrades.[2232]

[2231] NOPR, 179 FERC ¶ 61,194 at P 194.

[2232] *Id.* PP 194-195.

(b) Comments

1182. Many commenters generally support the proposal to develop standardized *pro forma* affected system agreements.[2233] Commenters state that standardization and better synchronization of timelines and processes for affected system studies between host and affected system transmission providers will improve the efficiency of the interconnection process and reduce opportunities for undue discrimination.[2234] ELCON suggests that standardization of affected system study agreements, modeling, and assumptions furthers certainty and accountability, resulting in a more transparent, efficient, and cost-effective interconnection process.[2235]

(c) Commission Determination

1183. We find that the lack of affected system *pro forma* study and facilities construction agreements hinders the efficiency of the generator interconnection process through increased litigation over such agreements and allows for potential unduly discriminatory behavior against interconnection customers whose interconnection requests necessitate affected system network upgrades. Our establishment of *pro forma*

[2233] Alliant Energy Initial Comments at 7; APPA-LPPC Initial Comments at 23; Clean Energy Associations Initial Comments at 48; ELCON Initial Comments at 8; Interwest Reply Comments at 17; Invenergy Initial Comments at 45; ISO-NE Initial Comments at 37-38; NARUC Initial Comments at 23-24; NYISO Initial Comments at 44-45; Pattern Energy Initial Comments at 26; Pine Gate Initial Comments at 42; SEIA Initial Comments at 34.

[2234] Consumers Energy Initial Comments at 8; Invenergy Initial Comments at 45; ISO-NE Initial Comments at 37-38.

[2235] ELCON Initial Comments at 8.

affected system agreements is supported by the record.[2236] We agree with commenters that this standardization of timelines and processes will improve the efficiency of the interconnection process and reduce opportunities for undue discrimination.[2237] For example, in establishing such standardized agreements, affected system transmission providers and affected system interconnection customers will no longer need to negotiate individual non-standard agreements. Also, in requiring affected system transmission providers to adhere to a set of *pro forma* procedures in their tariffs common to all jurisdictional transmission providers, we minimize the opportunities for undue discrimination.[2238] The standardization of affected system agreements also furthers certainty and accountability, resulting in a more transparent, efficient, and cost-effective interconnection process by ensuring affected system interconnection customers know the standard scope and terms of agreements for the affected system interconnection process prior to entering the interconnection queue.[2239]

[2236] *See id.*; Alliant Energy Initial Comments at 7; APPA-LPPC Initial Comments at 23; Clean Energy Associations Initial Comments at 48; Invenergy Initial Comments at 45; ISO-NE Initial Comments at 37-38; NARUC Initial Comments at 23-24; NYISO Initial Comments at 44-45; Pattern Energy Initial Comments at 26; Pine Gate Initial Comments at 42; SEIA Initial Comments at 34.

[2237] *See* Consumers Energy Initial Comments at 8; Invenergy Initial Comments at 45; ISO-NE Initial Comments at 37-38.

[2238] *See, e.g.*, Order No. 2003, 104 FERC ¶ 61,103 at P 11 (explaining that Commission precedent dating back to Order No. 888 establishes a need for standard procedures and agreements, in part to minimize opportunities for undue discrimination).

[2239] ELCON Initial Comments at 8.

ii. *Pro Forma* Affected System Study Agreement

(a) NOPR Proposal

1184. In the NOPR, the Commission proposed to establish a *pro forma* affected system study agreement to improve the efficiency and transparency of the interconnection customer's interaction with the affected system transmission provider.[2240] The Commission proposed to model the *pro forma* affected system study agreement on the form of the existing *pro forma* system impact study agreement, with necessary minor revisions to the party names.[2241] Specifically, the affected system interconnection customer and affected system transmission provider would be parties to the agreement.

1185. In articles 1, 2, 3, and 4, respectively, of the proposed *pro forma* affected system study agreement, the agreement specifies (1) the capitalization of defined terms in the *pro forma* LGIP, (2) that coordination with the host transmission provider shall occur pursuant to *pro forma* LGIP section 9, (3) that study assumptions shall be set forth in attachment A to the agreement, and (4) that studies shall be based on technical information provided by the affected system interconnection customer. In article 5, with regard to the information the affected system transmission provider will provide to the affected system interconnection customer in a study report upon completion of the affected system study, the Commission proposed to require the following: identification of any circuit breaker short circuit capability limits exceeded as a result of the

[2240] NOPR, 179 FERC ¶ 61,194 at P 197.

[2241] *Id.* P 198.

interconnection; identification of any thermal overload or voltage limit violations resulting from the interconnection; identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; a non-binding, good faith estimate of the cost of facilities on the affected system required to accommodate the interconnection of the affected system interconnection customer's project to the host transmission system; and a description of how such facilities will address the identified short circuit, instability, and power flow issues identified in the affected system study.[2242] The Commission sought comment on whether the information required for the study report would provide adequate information to the affected system interconnection customer to understand the results of the affected system study. Finally, in articles 6 and 7, the Commission specified the provision of an affected system study deposit and that standard miscellaneous terms would be used consistent with industry best practice and with the *pro forma* LGIP and *pro forma* LGIA.

(b) <u>Comments</u>

1186. Some commenters generally support the NOPR proposal to develop a *pro forma* affected system study agreement.[2243] Others generally support the establishment of a *pro forma* affected system study agreement but suggest general changes to the approach proposed in the NOPR. For example, MISO states that the requirement to execute an

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[2242] *Id.* P 199.

[2243] Ameren Initial Comments at 23; Duke Southeast Utilities Initial Comments at 18; North Carolina Commission and Staff Initial Comments at 24; U.S. Chamber of Commerce Initial Comments at 10-11.

agreement with each affected system interconnection customer would create a significant amount of work for transmission providers that is likely to divert resources from performing studies and coordinating with other transmission providers without any greater benefit than provided by existing joint operating agreements and other seams agreements with neighboring systems.[2244] SPP adds that requiring individualized invoicing for all affected system study requests from another transmission provider's cluster study would present a significant administrative burden for both transmission providers and interconnection customers, which would be required to deal with multiple transmission providers, instead of just the host transmission provider.[2245] SPP notes that, in its joint operating agreement with MISO, the transmission providers coordinate affected system studies following each transmission provider's system impact studies on their own systems, and rather than invoicing each interconnection customer individually, the transmission providers invoice each other for study costs, which allows the host transmission provider to use existing study deposits when available, and otherwise collect from its interconnection customers as needed.[2246]

1187. Other commenters suggest specific changes to the language proposed in the NOPR. For instance, Tri-State proposes adding language to article 9.4 of the *pro forma* LGIP specifying a protocol if deficiencies are not cured, such as, "shall be deemed

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[2244] MISO Initial Comments at 96.

[2245] SPP Initial Comments at 19.

[2246] *Id.* at 18-19.

withdrawn pursuant to Section 3.7 of this LGIP."[2247] PPL argues that the *pro forma* affected system study agreement should: (1) have article 7 replaced entirely with actual contractual terms; (2) contain a clear requirement for affected system interconnection customers to provide data in a timely manner; (3) include data ownership and confidentiality provisions; and (4) address restudies.[2248]

1188. Additionally, Tri-State includes an appendix containing a redline version of the *pro forma* affected system study agreement that specifies its requested revisions to the agreement. Of note, Tri-State proposes changes to article 6, which would require the affected system transmission provider to specify the affected system study deposit value.[2249]

1189. In response to whether the information required in the affected system study report would provide adequate information to the affected system interconnection customer to understand the results of the affected system study, Xcel states that the proposed information is adequate.[2250] Duke Southeast Utilities support the information required by article 5 of the proposed agreement but suggest that any other identified impacts outside of the prescribed information should also be included.[2251] LADWP believes that the

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[2247] Tri-State Initial Comments at 31-32.

[2248] PPL Initial Comments at 20.

[2249] Tri-State Initial Comments, app. B, at 122-124.

[2250] Xcel Initial Comments at 39.

[2251] Duke Southeast Utilities Initial Comments at 18.

study report should also include whether modifications to remedial action schemes or other special protection systems may be required.[2252]

1190. Enel seeks clarification on whether the affected system study scope must include all of "a short circuit analysis, thermal overload or voltage limit identification, and stability analysis, and a power flow analysis," as proposed in *pro forma* LGIP section 9.5, and requests that transmission providers be allowed to waive portions of the study scope if deemed unnecessary.[2253]

1191. Several entities ask the Commission to allow regional variations to avoid conflict with existing affected system coordination processes.[2254]

(c) <u>Commission Determination</u>

1192. We adopt, with modifications, the proposed *pro forma* affected system study agreement set forth in Appendix 9 of the *pro forma* LGIP.[2255] As discussed below, we make two modifications. First, consistent with comments,[2256] we establish a multiparty *pro forma* affected system study agreement set forth in Appendix 10 of the *pro forma* LGIP. Second, we modify article 6 of the proposed *pro forma* affected system study

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[2252] LADWP Initial Comments at 5.

[2253] Enel Initial Comments at 65.

[2254] Ameren Initial Comments at 23; MISO Initial Comments at 95; SPP Initial Comments at 18-19.

[2255] NOPR, 179 FERC ¶ 61,194 at P 197.

[2256] MISO Initial Comments at 96; SPP Initial Comments at 18-19.

agreement to make the language therein consistent with similar language elsewhere in the *pro forma* LGIP.[2257]

1193. Starting with the multiparty *pro forma* affected system study agreement, as described above, we require affected system transmission providers to study affected system interconnection requests in clusters. To facilitate this change, we modify the NOPR proposal and establish a *pro forma* multiparty affected system study agreement that closely tracks the proposed two-party agreement. Such a *pro forma* multiparty agreement will allow affected system transmission providers to enter into the same affected system study agreement with each of the affected system interconnection customers that it must study in a cluster. We find that a *pro forma* multiparty affected system study agreement will facilitate interactions with the affected system transmission provider, making them more efficient and transparent. We agree with SPP and MISO that a requirement for an affected system transmission provider to sign affected system study agreements with each affected system interconnection customer would be burdensome.[2258] In creating a *pro forma* multiparty affected system study agreement, we reduce the administrative burden on transmission providers that no longer need to manage several individual affected system study agreements.

[2257] We also make minor consistency edits to article 5 of the proposed *pro forma* affected system study agreement, to conform the *pro forma* affected system study agreement with *pro forma* LGIP section 9.6.

[2258] MISO Initial Comments at 96; SPP Initial Comments at 18-19.

1194. In response to SPP and MISO's suggestion to make the parties to the *pro forma* affected system study agreement the affected system transmission provider and the host transmission provider, we decline this request. We believe that the interconnection customer, as the one responsible for providing necessary information about the proposed generating facility as well as funding the affected system study, is the appropriate counterparty to the affected system study agreement. We note, however, that any transmission providers may propose alternative arrangements through joint operating agreements or otherwise pursuant to FPA section 205.

1195. In response to comments from Tri-State and PPL's request regarding affected system interconnection customers that fail to provide required information,[2259] we find that sufficient requirements for data sharing exist in both the current and newly adopted *pro forma* LGIP requirements. Specifically, as discussed above and consistent with comments from Tri-State, we modify *pro forma* LGIP section 9.5 to explicitly state that any affected system interconnection customer failing to submit required information and failing to cure that deficiency shall lose its affected system queue position. We also add to *pro forma* LGIP section 9.5 a requirement that the affected system transmission provider notify the host transmission provider in a timely manner of such failure by the affected system interconnection customer.

1196. In response to Tri-State's requested revisions to article 6 of the *pro forma* affected system study agreement, we modify the *pro forma* affected system study agreement to

[2259] PPL Initial Comments at 20; Tri-State Initial Comments at 18-19.

add additional language to explicitly require affected system interconnection customers to provide a study deposit. The deposit will provide for the cost of the affected system interconnection study. Moreover, we find that such revisions will align the *pro forma* affected system study agreement with Appendix 2 (cluster study agreement), Appendix 3 (interconnection facilities study agreement), and Appendix 4 (optional interconnection study agreement) of the *pro forma* LGIP.

1197. In response to PPL's request that article 7, regarding standard miscellaneous terms, should be replaced with actual contractual terms, we decline to adopt PPL's proposed revisions. We adopt article 7 of the *pro forma* affected system study agreement, with modification to eliminate the reference to the LGIA. We note that this article 7 is consistent with the existing *pro forma* interconnection system impact study agreement (which the Commission is replacing with new cluster study-based agreements adopted in this final rule), interconnection facilities study agreement, and optional interconnection study agreement, which also provide for standard miscellaneous terms. In response to PPL's requests that the *pro forma* affected system study agreement should address data ownership and confidentiality requirements as well as restudies, we find such revisions to the proposed *pro forma* affected system study agreement unnecessary, as they would be duplicative of existing *pro forma* LGIP provisions regarding confidentiality (section 13.1) and restudies (former section 6.4, now contained in sections 7.5, 8.5, and 9.10). Regarding the removal of the reference to the LGIA, we find that the removal is appropriate as the parties to an interconnection customer's LGIA would not be the same parties to an affected system study agreement.

1198. In response to comments on the scope of the *pro forma* affected system study, we agree with Xcel that the scope of the affected system study is adequate.[2260] Consequently, we decline to modify the scope of the affected system study contained in article 5 of the proposed *pro forma* affected system study agreement. We note that the scope of the affected system studies identified in article 5 is consistent with the scope of host system interconnection studies.[2261] In response to comments from Duke Southeast Utilities that entities should be able to include other, identified impacts in the affected system study report, we clarify that the scope of affected system studies must be consistent with the scope listed in article 5 of the *pro forma* affected system study agreement. Affording affected system transmission providers flexibility to expand the scope of affected system studies on an ad hoc or individual basis creates the potential for undue discrimination and a barrier to entry. With respect to LADWP's request to include impacts to remedial action schemes and other special protection systems within the scope of the affected system studies,[2262] we clarify that such impacts are already contemplated in article 5 of the *pro forma* affected system study agreement.

[2260] Xcel Initial Comments at 39.

[2261] *Pro forma* LGIP, app. 2, art. 5; app. 3, art. 4.

[2262] LADWP Initial Comments at 5.

iii. ***Pro Forma* Affected System Facilities Construction Agreement**

(a) **NOPR Proposal**

1199. In the NOPR, the Commission proposed to revise the *pro forma* LGIP to add a *pro forma* affected system facilities construction agreement.[2263] The proposed *pro forma* affected system facilities construction agreement includes provisions on the following: terms of the agreement; construction of network upgrades; taxes; *force majeure*; information reporting; security, billing, and payments; assignment; indemnity; breach, cure, and default; termination; contractors; confidentiality; information access and audit rights; dispute resolution; and notices.[2264] Proposed Appendix A to the agreement provides for details on identified network upgrades, cost estimates and responsibility, the construction schedule for network upgrades, and a payment schedule; proposed Appendix B addresses notification of completed construction; and proposed Appendix C provides for a transmission provider site map, a site plan, a plan and profile for network upgrades, and the estimated cost of the network upgrades.

1200. The Commission proposed that the *pro forma* affected system facilities construction agreement would be entered into by the affected system transmission provider and the affected system interconnection customer.[2265] Under the NOPR

[2263] NOPR, 179 FERC ¶ 61,194 at P 200.

[2264] *Id.* P 201.

[2265] *Id.* P 202.

proposal, the affected system transmission provider would be responsible for the design, procurement, construction, and installation of all network upgrades identified in Appendix A using reasonable efforts to complete construction consistent with the schedule identified in Appendix A. The affected system interconnection customer would initially fund the cost of any assigned network upgrades and be reimbursed by the affected system transmission provider.[2266] Rather, the Commission proposed to require that, consistent with Order No. 2003, the affected system interconnection customer must enter into an agreement with the affected system transmission provider that must specify the terms governing payments to be made by the affected system interconnection customer as well as payment of refunds by the affected system transmission provider for the full cost of network upgrades, plus interest.[2267]

1201. The Commission clarified that the term to be mutually agreed upon for payment of refunds to affected system interconnection customer funded network upgrades is not to exceed 20 years.[2268] This term mirrors the repayment term in the *pro forma* LGIA but allows for flexibility for the parties to come to another arrangement if they prefer. Under the NOPR proposal, within six months of completion of construction of any required network upgrades, the affected system transmission provider would invoice the affected

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[2266] Order No. 2003, 104 FERC ¶ 61,103 at P 738.

[2267] *Id.* P 739.

[2268] *Id.*; *see also* Order No. 2003-B, 109 FERC ¶ 61,287 at PP 32-36 (extending the required repayment period from five years to 20 years).

system interconnection customer for the final construction costs, including a true-up of estimated and actual costs. The *pro forma* affected system facilities construction agreement would terminate upon the affected system transmission provider's final repayment to the affected system interconnection customer. Alternatively, the affected system interconnection customer could also terminate the affected system facilities construction agreement with 60 calendar days' written notice to the affected system transmission provider.

1202. The Commission sought comment on the network upgrade funding and repayment provisions in the proposed *pro forma* affected system facilities construction agreement, specifically whether the repayment time frame and the similarity of the proposal to the repayment terms in the *pro forma* LGIA were appropriate.[2269] The Commission also sought comment on whether any articles or provisions should be added to the proposed *pro forma* affected system facilities construction agreement or whether the proposed provisions were sufficient.[2270]

(b) <u>Comments</u>

1203. Some commenters generally support the proposed *pro forma* affected system facilities construction agreement because it will offer uniformity across the country and increase administrative efficiency.[2271] Others argue that the agreement should be

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[2269] NOPR, 179 FERC ¶ 61,194 at P 203.

[2270] *Id.* P 204.

[2271] Ameren Initial Comments at 23; Duke Southeast Utilities Initial Comments at

structured as either an individual network upgrade agreement or a multiparty network upgrade agreement.[2272]

1204. Some commenters request that the Commission allow for regional variations to avoid conflict with existing *pro forma* facilities construction agreements.[2273]

(1) <u>Comments on Specific Provisions and Related Proposals</u>

1205. As a global change, Xcel recommends that the defined term "affected system operator" be used instead of "transmission provider" when referencing the affected system transmission provider, arguing that the use of the terms "transmission provider" and "transmission provider acting as affected system" are confusing and may conflict with usage of those terms in the LGIP.[2274]

1206. With regard to article 2 (Term of Agreement), Tri-State proposes the following addition: "No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery."[2275] Additionally, Tri-State opposes the option in

18; SPP Initial Comments at 19-20.

[2272] PPL Initial Comments at 20; SPP Initial Comments at 20.

[2273] Ameren Initial Comments at 23; MISO Initial Comments at 97; NYISO Initial Comments at 45; PPL Initial Comments at 22.

[2274] Xcel Initial Comments at 40.

[2275] Tri-State Initial Comments at 32.

proposed article 2.2.1 that would allow the affected system interconnection customer to terminate the affected system facilities construction agreement with 60 calendar days' written notice. Tri-State contends that allowing such termination could trigger restudies for the affected system transmission provider.[2276]

1207. Southern states that the Commission should either reconsider or clarify proposed article 2.2.2 (Termination Upon Default) and proposed article 5.2 (Notice of Breach, Cure, and Default), which it states appears to provide that if a default does not pose a threat to the reliability of the affected system transmission provider's transmission system, the affected system transmission provider may not terminate the agreement if the affected system interconnection customer has begun to cure and compensate the transmission provider for any damage.[2277] Southern argues that such provisions should be consistent with *pro forma* LGIA provisions and that, if an affected system interconnection customer defaults under the LGIA, the affected system operator should not be required to build affected system network upgrades. Southern argues that, if the provisions are not consistent with the *pro forma* LGIA, affected system transmission providers will build affected system network upgrades that are not needed, and there will be different default and termination rights applicable to these improvements. Similarly, Tri-State submits suggested edits to proposed article 2.2.2, which remove the provisions

[2276] *Id.* at 21.

[2277] Southern Initial Comments at 18.

Southern comments on, explaining that a default should only occur after a breach and failure to cure.[2278]

1208. Invenergy opposes proposed article 2.2.3, which provides that, upon termination of the affected system facilities construction agreement, the affected system interconnection customer would be responsible for costs incurred by another affected system interconnection customer due to the termination of: (1) its affected system facilities construction agreement; (2) that interconnection customer's LGIA; or (3) any of that interconnection customer's other affected system facilities construction agreements.[2279] Some commenters argue that this requirement is unreasonable and must be revised.[2280] They claim that there is no basis for imposing on the affected system interconnection customer broad and potentially exorbitant liability for any potential impacts on any other interconnection customer within the affected system, which they argue exceeds potential liability imposed under the *pro forma* LGIA for the host transmission provider's transmission system.[2281] Invenergy states that the provision appears to be based on a provision in MISO's *pro forma* facilities construction

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[2278] Tri-State Initial Comments at 33.

[2279] Invenergy Initial Comments at 45.

[2280] *Id.* at 46; Interwest Reply Comments at 18-19; Tri-State Initial Comments at 20.

[2281] Interwest Reply Comments at 18-19; Invenergy Initial Comments at 46; Tri-State Initial Comments at 20.

agreement, which it argues does not make sense for a generically applicable *pro forma* agreement.

1209. As for proposed article 3 (Construction of Network Upgrades), some commenters object to limiting the right to suspend for *force majeure* events, contained in proposed article 3.1.2.1.[2282] Southern states that proposed article 3.1.2.1 appears to provide that the affected system interconnection customer may only suspend its interconnection request if there is a *force majeure* event and that no such limitation on suspension rights exists under the *pro forma* LGIA, meaning that an affected system interconnection customer could suspend its interconnection request under the *pro forma* LGIA but still be required to move forward with construction of affected system network upgrades, if the reason for suspension under the *pro forma* LGIA is not a *force majeure* event.[2283] Enel asserts that the Commission has not provided justification for limiting the affected system interconnection customer's suspension rights to just *force majeure* events.[2284] Enel, Invenergy, and Southern argue that suspension rights under the *pro forma* affected system facilities construction agreement should be consistent with the suspension rights under the *pro forma* LGIA, with Invenergy highlighting that the *pro forma* LGIA permits suspension for up to three years.[2285] Conversely, Tri-State argues that the same *force*

[2282] Enel Initial Comments at 83-84; Invenergy Initial Comments at 47; Southern Initial Comments at 18; Tri-State Initial Comments at 20.

[2283] Southern Initial Comments at 18-19.

[2284] Enel Initial Comments at 83-84.

[2285] *Id.* at 83; Invenergy Initial Comments at 47; Southern Initial Comments at 18-

majeure language used in proposed article 3.1.2.1 should be added to both the *pro forma* LGIA and *pro forma* LGIP.[2286]

1210. MISO suggests that there should be a provision in the *pro forma* affected system facilities construction agreement on cross-defaults between the affected system facilities construction agreement and the interconnection customer's LGIA.[2287] MISO asserts that, as proposed, if the affected system interconnection customer refuses to make payments under an affected system facilities construction agreement, it is unclear how it would affect the affected system interconnection customer's LGIA.

1211. In response to proposed article 3.2.2.1, which would require affected system transmission providers to reimburse affected system interconnection customers for their affected system network upgrade costs, many commenters support the proposal,[2288] while many others oppose it.[2289] In support, commenters contend that the reimbursement policy is consistent with long-established Commission precedent and cost causation, as it

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[2286] Tri-State Initial Comments at 33.

[2287] MISO Initial Comments at 97.

[2288] ACE-NY Initial Comments 9; AES Initial Comments at 22; Ameren Initial Comments at 23; APPA-LPPC Initial Comments at 23; Enel Initial Comments at 66-67; Shell Initial Comments at 33-34.

[2289] AECI Initial Comments at 9; Duke Southeast Utilities Initial Comments at 19; EEI Initial Comments at 18-19; North Carolina Commission and Staff Initial Comments at 6; PG&E Reply Comments at 5-6; PPL Initial Comments at 20; Southern Reply Comments at 7-8; Tri-State Initial Comments at 21-22; U.S. Chamber Commerce Initial Comments at 11; WAPA Initial Comments at 13-14; Xcel Initial Comments at 40.

ensures that affected system network upgrade cost reimbursement is rate-based, such that the transmission customers that ultimately benefit from the network upgrades pay for those upgrades.[2290] In contrast, according to these commenters, allowing transmission customers of the affected system to receive the benefits of an affected system network upgrade, without paying for it, would create a "free-rider" problem that is inconsistent with the "beneficiary pays" principle.[2291]

1212. Other commenters do not fully oppose the proposal but suggest changes to proposed article 3.2.2.1. For instance, MISO and Southern contend that the repayment provisions for affected system interconnection customers should be consistent with how the transmission provider repays its internal interconnection customers.[2292] MISO asserts that this will ensure comparability and non-discriminatory treatment between affected system interconnection customers and "native" interconnection customers interconnected to the affected system.[2293] APPA-LPPC argue that the NOPR proposal is missing an express, contractual commitment ensuring that an interconnection customer will fund network upgrades identified by the affected system as a condition of interconnection.[2294] APPA-LPPC state that they believe this to be implicit in the proposal and that the

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[2290] Enel Initial Comments at 66; Shell Initial Comments at 35.

[2291] ACE-NY Initial Comments 9; Shell Initial Comments at 35-36.

[2292] MISO Initial Comments at 97; Southern Initial Comments at 4.

[2293] MISO Initial Comments at 97.

[2294] APPA-LPPC Initial Comments at 24-25.

provision should specify that the identified affected system transmission provider is an intended third-party beneficiary of the LGIA. APPA-LPPC contend that the absence of such a contractual obligation on the part of the interconnection customer is a particular concern for non-public utilities, which have no standing under the FPA to seek funding for network upgrades under Commission-jurisdictional tariffs. However, according to Southern, in Order No. 2003, the Commission declined to make a generic finding on the possibility of network upgrade costs being passed onto native load and transmission customers and instead allowed transmission providers to make a filing if such entities were not being held harmless.[2295] Southern states that the Commission should clarify that a transmission provider can make such a filing, if warranted, in which it could propose that affected system interconnection customers bear the cost responsibility of identified affected system network upgrades.[2296]

1213. Among issues raised by commenters that oppose the proposal, one common concern is that the proposal would force affected system transmission providers to subsidize interconnection to neighboring transmission systems, despite potentially not receiving any energy from such interconnection customers, causing increased costs to the affected system due to the requirement to mitigate negative thermal, voltage, and stability

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[2295] Southern Initial Comments at 17-18; Southern Reply Comments at 8 (citing Order No. 2003-A, 106 FERC ¶ 61,220 at P 586; Order No. 2003-B, 109 FERC ¶ 61,287 at P 56).

[2296] Southern Initial Comments at 17-18; Southern Reply Comments at 9-10.

impacts without a corresponding increase in benefits.[2297] North Carolina Commission and Staff also contend that the Commission has not provided evidence on this matter that would allow the Commission to meet its burden under FPA section 206.[2298] Some commenters assert that the affected system interconnection customer should be responsible for the costs of affected system network upgrades in exchange for use of the affected system (i.e., via transmission service).[2299] Xcel notes that, for loop flow impacts, the affected system interconnection customer may not formally take transmission service but may be granted the right to the transmission capacity associated with the loop flows they cause, and some transmission providers have charged unreserved use for such impacts or otherwise required neighbors to pay for the transmission use.[2300]

1214. North Carolina Commission and Staff observe that, if the Commission were to implement the NOPR proposal and allow RTOs/ISOs to obtain independent entity variations from the proposed affected system pricing scheme implementing a participant funding model, then North Carolina retail and wholesale customers of Duke Energy Carolinas and Duke Energy Progress would be paying for affected system network

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[2297] AECI Initial Comments at 9; Duke Southeast Utilities Initial Comments at 21-22, 26; EEI Initial Comments at 18-19; North Carolina Commission and Staff Initial Comments at 6; PPL Initial Comments at 21; Tri-State Initial Comments at 21-22; U.S. Chamber of Commerce Initial Comments at 11-12; Xcel Initial Comments at 40.

[2298] North Carolina Commission and Staff Initial Comments at 16.

[2299] Tri-State Initial Comments at 20; Xcel Initial Comments at 40.

[2300] Xcel Initial Comments at 40.

upgrade costs when a generating facility interconnects with the PJM-controlled transmission system in addition to paying for network upgrade costs for native interconnection customers when generating facilities interconnect with Duke Energy Progress or Duke Energy Carolinas-owned transmission facilities, which they argue would be patently unjust, unfair, and unduly preferential.[2301]

1215. Several commenters argue that the NOPR proposal is contrary to important objectives articulated in Order No. 2003.[2302] For instance, Duke Southeast Utilities contend that, if transmission providers are required to reimburse affected system interconnection customers for costs advanced for affected system network upgrades, such transmission providers will seek to obtain rate recovery of their reimbursement cost from existing wholesale and retail transmission customers, meaning those classes of customers will not be protected from adverse rate implications because they will have to absorb all affected system network upgrade costs.[2303] According to Duke Southeast Utilities, this is contrary to an important objective articulated in Order No. 2003-B of the interconnection pricing policy protecting existing transmission customers from adverse rate implications

[2301] North Carolina Commission and Staff Initial Comments at 23.

[2302] Duke Southeast Utilities Initial Comments at 23; PPL Initial Comments at 20-21.

[2303] Duke Southeast Utilities Initial Comments at 23.

associated with interconnection facilities and network upgrades required to interconnect a new generating facility.[2304]

1216. According to PPL, the pricing policy established in Order No. 2003 was meant to promote competition in markets "still dominated by non-independent transmission providers."[2305] PPL argues that non-RTO/ISO transmission providers no longer dominate, and therefore this policy is no longer necessary.[2306] PPL asserts that, contrary to the time of Order No. 2003's issuance, and as a result of the size and nature of generating facilities being developed in RTO/ISO regions, non-RTOs/ISOs might be required to build costly affected system network upgrades to accommodate the interconnection of generating facilities in adjacent markets. PPL contends that affected system network upgrade costs can overwhelm the total network upgrade costs identified for reliability or other planning purposes. PPL claims, however, that the affected system network upgrade reimbursement proposal in the NOPR is directly contrary to the Commission's interconnection pricing policy meant to protect existing customers from the rate impacts of interconnection-related network upgrades,[2307] and allows affected system interconnection customers to benefit from network upgrades without paying for

[2304] *Id.* (citing Order No. 2003-B, 109 FERC ¶ 61,287 at P 56).

[2305] PPL Initial Comments at 20 (citing Order 2003-A, 106 FERC ¶ 61,220 at P 636).

[2306] *Id.* at 20-21.

[2307] *Id.* at 21 (citing Order 2003-A, 106 FERC ¶ 61,220 at P 586; Order 2003-B, 109 FERC ¶ 61,287 at P 56).

them.[2308] Thus, PPL asserts that the Commission should allow affected system transmission providers the flexibility to directly assign affected system network upgrade costs. Duke Southeast Utilities concur, asserting that there is ample precedent of the Commission accepting, without modification, an affected system operating agreement between affected system transmission providers and affected system interconnection customers that directly assign network upgrade costs to such interconnection customers without reimbursement.[2309]

1217. Invenergy asserts that the Commission should reject arguments challenging the Commission's interconnection pricing policy established in Order No. 2003.[2310] Invenergy contends that this interconnection pricing policy was fully litigated in the Order No. 2003 rulemaking proceeding and that issues relating to cost causation were fully and carefully considered at that time.[2311] Invenergy also argues that Duke Southeast Utilities' reference to Order No. 2003-B is misplaced, as the Commission, in Order No. 2003-B, found that the interconnection pricing policy fully protected native load

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[2308] *Id.* at 21-22.

[2309] Duke Southeast Utilities Initial Comments at 24 (citing, e.g., Docket No. ER21-1701-000 (involving acceptance of an affected system upgrade agreement between Southern and Cooperative Energy)).

[2310] Invenergy Reply Comments at 10 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 693-696).

[2311] *Id.* at 11-12 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 684, 693-696).

customers and that transmission providers could make and justify alternative proposals on compliance.[2312]

1218. Duke Southeast Utilities and North Carolina Commission and Staff assert that the affected system network upgrade reimbursement proposal will stifle renewable generating facility development.[2313] For instance, Duke Southeast Utilities argue that mandatory reimbursement has the likelihood of chilling development of new, mainly renewable, generating facilities in states that consider such costs as part of overall development costs when considering whether to issue a certificate of public convenience and necessity to permit these generating facilities.[2314]

1219. Moreover, Duke Southeast Utilities argue that the mandatory reimbursement by affected system transmission providers of affected system network upgrade costs fails to encourage efficient siting decisions by affected system interconnection customers.[2315] Duke Southeast Utilities assert that, if affected system interconnection customers are reimbursed for 100% of the costs of network upgrades on the affected system plus

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[2312] *Id.* at 10-11.

[2313] Duke Southeast Utilities Initial Comments at 24-25; North Carolina Commission and Staff Initial Comments at 21.

[2314] Duke Southeast Utilities Initial Comments at 24-25.

[2315] *Id.* at 25; Duke Southeast Utilities Reply Comments at 23.

interest at the Commission-prescribed rate, they actually profit financially from such reimbursement.[2316]

1220. Invenergy argues that the possibility of certain states considering affected system network upgrade costs in permitting proceedings does not call the Commission's existing pricing policy into question.[2317] In response to arguments that the NOPR proposal could foster inefficient siting, Invenergy asserts that this argument was considered and settled in the Order No. 2003 rulemaking proceeding.[2318] Invenergy contends that such comments are speculative and ignore other facts, such as that identification of affected system network upgrades typically occurs after most siting decisions are made.

1221. North Carolina Commission and Staff argue that affected system costs are no longer incidental or rare and have been escalating over time.[2319] North Carolina Commission and Staff allege that the proposed crediting policy will force North Carolina wholesale and retail ratepayers to subsidize the policy choices of other states and the corporate goals of businesses located in other states.

1222. Public Interest Organizations urge the Commission to disregard North Carolina Commission and Staff's assertions on this matter, arguing that the NOPR proposal is

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[2316] Duke Southeast Utilities Initial Comments at 25.

[2317] Invenergy Reply Comments at 12.

[2318] *Id.* (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 695-696).

[2319] North Carolina Commission and Staff Initial Comments at 21-22.

unrelated to state and corporate policies.[2320] Public Interest Organizations assert that the proposal is meant to address existing gaps in the *pro forma* LGIP that apply to all interconnection customers regardless of fuel type and motivation for generating facility development.

1223. WAPA expresses significant concerns with the NOPR proposal, emphasizing that it requires the affected system transmission provider to reimburse the affected system interconnection customer cash plus interest over 20 years for the cost of affected system network upgrades.[2321] WAPA states that, as a federal agency, it cannot provide a cash payment with interest to an interconnection customer that does not take transmission service from WAPA.[2322] According to WAPA, per its tariff, it only provides network credits, not cash payments, for such customers, and it would need to work with the host transmission provider to ensure a mechanism is developed to properly credit the affected system interconnection customer.[2323]

[2320] Public Interest Organizations Reply Comments at 18-19.

[2321] WAPA Initial Comments at 13.

[2322] *Id.* Specifically, WAPA states that it must deposit all revenues received into a reclamation fund and that it would need an appropriation from Congress to use the money in the reclamation fund to pay interconnection customers. *Id.* at 13 n.17 (citing 43 U.S.C.392a). WAPA also notes that its current tariff specifically provides that WAPA cannot pay interest on any funds advanced by interconnection customers. *Id.* (citing WAPA, WAPA Open Access Transmission Tariff, section 17.3 (1.0.0)).

[2323] *Id.* at 13-14.

1224. Also on proposed article 3 of the *pro forma* affected system facilities construction agreement, Tri-State notes that proposed article 3.2.2.1 (Repayment) does not contain a reference to determine if affected system network upgrades are unnecessary.[2324] Separately, Tri-State also suggests revisions to state that the repayment period should end no later than 20 years from the completion of the construction of the affected system interconnection customer's generating facility, rather than completion of the construction of the affected system network upgrades.[2325]

1225. With regard to proposed article 4 (Security, Billing, and Payments), PacifiCorp offers suggested revisions to proposed article 4.1, which PacifiCorp asserts are intended to, among other things, clarify that additional security will be required from the affected system interconnection customer if the affected system transmission provider determines that the costs of facilities may exceed the initial estimate provided to the affected system interconnection customer.[2326] PPL also states that affected system interconnection customers should be required to meet credit and security requirements.[2327]

1226. As for proposed article 6 (Termination of Agreement), Tri-State suggests consolidating proposed article 6.3.3 (Pre-construction of Installation) with proposed

[2324] Tri-State Initial Comments at 33.

[2325] *Id.*, app. B at 133.

[2326] PacifiCorp Initial Comments at 37.

[2327] PPL Initial Comments at 20.

article 2.2.3 and proposes removing some language in proposed article 6.4 (Survival Rights) that it argues is duplicative of proposed article 2.4.[2328]

1227. Commenters also respond to the proposed confidentiality provisions. Southern asserts that proposed article 8.1 in the *pro forma* affected system facilities construction agreement, section 13.1 in the *pro forma* LGIP, and article 22 in the *pro forma* LGIA should be revised to reflect the use of backup servers and the obligations of transmission providers to share information under NERC Reliability Standards.[2329] Southern asserts that it is administratively difficult to meet the requirements in these provisions that specify that confidential information be destroyed or returned, arguing that this provision should allow information to be stored on backup servers. Southern also notes that, under NERC Reliability Standards, which were developed after the effective date of Order No. 2003, transmission providers must disclose confidential information to neighboring transmission providers, and therefore, this language should be updated to reflect that the transmission provider must share this confidential information.

1228. Moving to proposed Appendix A, MISO contends that there is no need for a commercial operation date to be listed for affected system network upgrades in proposed Appendix A.[2330] MISO argues that commercial operation is something that occurs in the

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[2328] Tri-State Initial Comments at 33-34.

[2329] Southern Initial Comments at 19.

[2330] MISO Initial Comments at 97.

LGIA context, where the affected system interconnection customer's injection of energy onto the host transmission provider is memorialized.

(2) Requests for Clarification

1229. Southern explains that the *pro forma* LGIA and Commission policy require that interconnection customers pay for the cost of system protection facilities, and Southern requests that the Commission clarify that it is not changing this policy.[2331]

(3) Miscellaneous

1230. Eversource states that the concerns of interconnection customers and transmission providers with regard to ISO-NE's related facilities agreement (RFA)[2332] are not addressed by the NOPR proposal, which address coordination between different tariffs and system operators, and requests that the Commission clarify this difference.[2333]

(c) Commission Determination

1231. We adopt, with modifications, the NOPR proposal to establish a *pro forma* affected system facilities construction agreement in Appendix 11 of the *pro forma* LGIP.[2334] The *pro forma* affected system facilities construction agreement, as adopted herein, closely tracks the NOPR proposal: the affected system transmission provider and

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[2331] Southern Initial Comments at 17; Southern Reply Comments at 8 (citing *pro forma* LGIA art. 9.7.4.1; Order No. 845, 163 FERC ¶ 61,043 at P 371).

[2332] ISO-NE's RFA is an intra-RTO/ISO agreement with a specific transmission owner.

[2333] Eversource Initial Comments at 32.

[2334] NOPR, 179 FERC ¶ 61,194 at P 197.

the affected system interconnection customer(s) will enter into the agreement; and the agreement will set forth the terms and conditions by which the affected system transmission provider will be responsible for the design, procurement, construction, and installation of all network upgrades and terms and conditions by which the affected system interconnection customer will initially fund, and be reimbursed for, the cost of any assigned affected system network upgrades. As described below, we modify the following proposed articles in the *pro forma* affected system facilities construction agreement: (1) article 2.2.2 (Termination Upon Default); (2) article 2.2.3 (Consequences of Termination); (3) article 3.1.1 (Transmission Provider Obligations); (4) article 3.1.2.1 (Right to Suspend); (5) article 3.1.2.3 (Right to Suspend Due to Default); (6) article 5.1 (Events of Breach); (7) article 5.2 (Notice of Breach, Cure and Default); (8) article 5.2.1; and (9) article 5.2.2.[2335] Additionally, we establish a *pro forma* multiparty affected system facilities construction agreement set forth in Appendix 12 of the *pro forma* LGIP.

1232. We find that a *pro forma* affected system facilities construction agreement will improve the efficiency of the interconnection process by reducing delays through improved coordination among relevant parties, consistent with the Commission's preliminary findings in the NOPR and with record support.[2336] As Duke Southeast

[2335] We further note that we streamline article 6.2 (Termination and Removal) of the *pro forma* affected system facilities construction agreement with ministerial revisions, as well as add article 5.2 to provide a definition of "breaching party," which changes the numbering for proposed article 5.2 (Notice of Breach, Cure, and Default) to article 5.3 and proposed article 5.3 (Rights in the Event of Default) to article 5.4.

[2336] NOPR, 179 FERC ¶ 61,194 at P 200; *see also* Ameren Initial Comments at 23; Duke Southeast Utilities Initial Comments at 18; Pine Gate Initial Comments at 42; SPP

Utilities explains, the adoption of a *pro forma* affected system facilities construction agreement will offer uniformity of these types of agreements to be tendered by affected system transmission providers across the country.[2337] Such uniformity will help reduce the potential for undue discrimination. As the Commission found in Order No. 2003, a standard set of procedures as part of the tariff for all jurisdictional transmission facilities will minimize opportunities for undue discrimination.[2338]

1233. We also adopt a *pro forma* multiparty affected system facilities construction agreement.[2339] Similar to adopting the *pro forma* multiparty affected system study agreement, as discussed earlier, we find that the adoption of the *pro forma* multiparty affected system facilities construction agreement will further improve coordination and further minimize opportunities for undue discrimination, even relative to a two-party agreement. Also, similar to the adoption of the *pro forma* affected system study agreement, the establishment of the *pro forma* multiparty affected system facilities construction agreement aligns with the requirement to study affected system interconnection requests in clusters. Specifically, such a multiparty agreement will allow for a common agreement for the affected system transmission provider to enter into with all affected system interconnection customers for the construction of affected system

Initial Comments at 19-20.

[2337] Duke Southeast Utilities Initial Comments at 18.

[2338] Order No. 2003, 104 FERC ¶ 61,103 at P 11.

[2339] PPL Initial Comments at 20; SPP Initial Comments at 19-20.

network upgrades identified by the cluster study that are assigned to more than one affected system interconnection customer. Below, in discussing relevant article-specific comments, we discuss noteworthy, additional changes needed to convert the *pro forma* affected system facilities construction agreement from a two-party agreement to a multiparty agreement.

1234. As with the *pro forma* multiparty affected system study agreement, discussed above, the *pro forma* multiparty affected system facilities construction agreement that we adopt in this final rule closely follows the two-party agreement, with changes needed to convert to a multiparty agreement. In article 2.2.2 (Termination Upon Default), we establish that the default by one affected system interconnection customer does not allow the non-defaulting affected system interconnection customer(s) the right to terminate the agreement and that, instead, the defaulting party may be removed from the agreement by the affected system transmission provider. In article 3.1.2.1 (Right to Suspend), we maintain the affected system interconnection customer's right to suspend but only upon the mutual agreement of all affected system interconnection customers that are party to the multiparty agreement. In article 5.3 (Notice of Breach, Cure, and Default), we establish multiparty cure procedures whereby the non-breaching parties may cure the other affected system interconnection customer's breach.

1235. We decline to make changes to the proposed *pro forma* affected system facilities construction agreement and conforming changes to the *pro forma* LGIP**,** aligning with Xcel's suggestion that the "affected system transmission provider" should be renamed an "affected system operator." Instead, we clarify that the *pro forma* LGIP is written for a

specific transmission provider. When a transmission provider is fulfilling its obligations as a host transmission provider, the *pro forma* LGIP refers to the host transmission provider's interaction with the "affected system operator." However, when the *pro forma* LGIP references a transmission provider and its obligations as the operator of an affected system, we use the term "transmission provider," as the *pro forma* LGIP is setting the requirements of the transmission provider, whether acting as the host or affected system transmission provider, and that is a different perspective from a host transmission provider's interaction with a separate "affected system operator."

1236. In response to Tri-State's suggestion to revise proposed article 2 of the *pro forma* affected system facilities construction agreement to clarify that the execution of an LGIA does not convey transmission service, we decline to adopt this request, as it is unnecessary.[2340] However, we accept Tri-State's suggested revisions to article 3.1.1 of the *pro forma* affected system facilities construction agreement to clarify that the affected system transmission provider shall not undertake any actions inconsistent with its safety practices, material and equipment specifications, design criteria and construction procedures, labor agreements, or any applicable laws and regulations.

[2340] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 118 (stating that "[t]he Commission continues to treat interconnection and delivery as separate aspects of transmission service, and an Interconnection Customer may request Interconnection Service separately from transmission service (delivery of the Generating Facility's power output)"); Order No. 2003-A, 106 FERC ¶ 61,220 at P 113 ("reiterat[ing] that Interconnection Service is separate from the delivery component of Transmission Service and that the mere interconnection of the Generating Facility is unlikely to harm reliability on Affected Systems").

1237. We modify proposed articles 2.2.2 and 5.2 (now articles 2.2.2 and 5.3) of the *pro forma* affected system facilities construction agreement in response to comments from Southern and Tri-State regarding termination and cure. Proposed article 2.2.2 establishes that a non-breaching party has the right to terminate the *pro forma* affected system facilities construction agreement, provided that termination does not pose a reliability threat and that the breaching party has not undertaken efforts to cure the breach, pursuant to article 5.3 (Notice of Breach, Cure and Default). However, consistent with comments from Southern,[2341] we agree that termination and default rights in the *pro forma* affected system facilities construction agreement should be consistent with the *pro forma* LGIA. Accordingly, as adopted, we modify articles 2.2.2 and 5.2 (now articles 2.2.2 and 5.3) of the *pro forma* affected system facilities construction agreement to make them consistent with the existing default provisions in article 17 of the *pro forma* LGIA (Default), which also establishes default and cure provisions in the event of a breach.

1238. We also modify proposed article 2.2.3 (Consequences of Termination) of the *pro forma* affected system facilities construction agreement in response to comments from Tri-State and Invenergy suggesting that it would require affected system interconnection customers to be responsible for the costs of additional facilities that are caused by another interconnection customer terminating its affected system facilities construction agreement or that interconnection customer's LGIA.[2342] Specifically, we remove the final sentence

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[2341] Southern Initial Comments at 18.

[2342] Invenergy Initial Comments at 45; Tri-State Initial Comments at 20.

from proposed article 2.2.3 that an "affected system interconnection customer is responsible for the cost of additional facilities that is caused to another interconnection customer due to the termination of this Agreement, affected system interconnection customer's LGIA, or any affected system interconnection customer's other Affected System Facilities Construction Agreement(s)." We find that deletion of this sentence is needed because the affected system interconnection customer should not be responsible for any additional facilities that are assigned to another interconnection customer under these circumstances. As written, the provision implies that an affected system interconnection customer could be responsible for any network upgrade identified as a result of the agreement's termination, even if the newly assigned network upgrade is on a different transmission provider's transmission system than the transmission provider that is a signatory to the terminated agreement. Additionally, we note that the *pro forma* LGIA contains no similar requirement that upon termination of an LGIA that the interconnection customer is responsible for any additional costs assigned to another interconnection customer as a result of the LGIA's termination and based on the comments received, the record does not support including the provision.

1239. MISO requests a cross-default provision between the *pro forma* affected system facilities construction agreement and the *pro forma* LGIA because MISO asserts that, if an affected system interconnection customer does not meet its obligations under its affected system facilities construction agreement, it is unclear how that would affect that

interconnection customer's LGIA on its host transmission system.[2343] In response, we clarify that a breach under the *pro forma* affected system facilities construction agreement does not constitute a breach under the *pro forma* LGIA. We are unpersuaded that cross-default provisions between the *pro forma* affected system facilities construction agreement and the *pro forma* LGIA are necessary because both the *pro forma* affected system facilities construction agreement and the *pro forma* LGIA individually already contain default provisions.

1240. In addition, we are concerned that a cross-default provision, which could result in the termination of an interconnection customer's interconnection service based on actions under a separate agreement, could raise contractual complications because the host transmission provider will not be a party to the affected system facilities construction agreement. We note, however, that any affected system interconnection customer that defaults on its obligations under the *pro forma* affected system facilities construction agreement may face consequences, including, for example, curtailment. Additionally, we find that article 4.1 of the *pro forma* affected system facilities construction agreement already contains sufficient security provisions to protect a transmission provider in the situation that the affected system interconnection customer defaults on the agreement and which discourages non-payment by the interconnection customer.

1241. We modify proposed article 3.1.2.1 (Right to Suspend for *Force Majeure* Event) of the *pro forma* affected system facilities construction agreement in response to

[2343] MISO Initial Comments at 97.

comments that the proposed suspension provision is too restrictive and inconsistent with the suspension provision in the *pro forma* LGIA.[2344] Specifically, we revise article 3.1.2.1 to remove the limitation on the right to suspend to *force majeure* events and modify the suspension provision to allow an affected system interconnection customer to suspend work required under the affected system facilities construction agreement for up to three years.[2345] We also modify article 3.1.2.1 to remove the requirement for the affected system interconnection customer, prior to suspension, to provide security to the affected system transmission provider of the higher of $5 million or the total cost of all affected system network upgrades listed in Appendix A of the agreement. We find the requirement unnecessary because, under article 4.1 (Provision of Security) of the *pro forma* affected system facilities construction agreement, the affected system interconnection customer would have already been required to provide security for the applicable portion of the affected system network upgrades. With these changes to article 3.1.2.1, the suspension provision in the *pro forma* affected system facilities construction agreement will mirror the suspension provision in the *pro forma* LGIA.[2346]

1242. Additionally, we revise proposed article 3.1.2.3 (Right to Suspend Due to Default) of the *pro forma* affected system facilities construction agreement, which provides for the

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[2344] *Pro forma* LGIA art. 5.16.

[2345] We also make various conforming revisions throughout proposed article 3.1.2.1 of the *pro forma* affected system facilities construction agreement, consistent with this modification to the suspension provision.

[2346] *Pro forma* LGIA art. 5.16.

right to suspend due to default. The revisions we adopt to this provision clarify that if an affected system interconnection customer defaults, the affected system interconnection customer will be responsible for any additional expenses incurred by the affected system transmission provider associated with the construction and installation of the affected system network upgrades, as set forth in article 2.2.3 (Consequences of Termination). We find that the revisions will align the language in the *pro forma* affected system facilities construction agreement with similar language in the *pro forma* LGIP, as suggested by PacifiCorp.[2347] However, we reject the proposed revisions suggested by Tri-State to article 3.1.2.3 because they would alter the right to suspend to allow an affected system transmission provider the right to suspend in the event of a breach, rather than in the event of a default. Tri-State's suggested changes to article 3.1.2.3 would contradict other provisions in the *pro forma* LGIA and the *pro forma* affected system facilities construction agreement, which allow for the breaching party to cure a breach as is appropriate.

1243. We adopt article 3.2.2.1 (Repayment) of the *pro forma* affected system facilities construction agreement as proposed, which is consistent with existing Commission precedent.[2348]

[2347] PacifiCorp Initial Comments, attach. A, at 54.

[2348] Order No. 2003, 104 FERC ¶ 61,103 at PP 693-696, 720-739; Order No. 2003-A, 106 FERC ¶ 61,220 at PP 584-586 (stating that the transmission system is a cohesive, integrated network that operates as a single piece of equipment, and that network facilities benefit all transmission customers; further, even if a customer can be said to have caused the addition of a grid facility, such addition represents a system expansion used by and benefiting all users due to the integrated nature of the grid); Order

1244. Some commenters are concerned that affected systems repayment could force affected system transmission providers to subsidize interconnection to neighboring systems, stifle renewable generating facility development, or facilitate inefficient siting.[2349] However, in the NOPR, the Commission did not propose to change the Commission's affected system repayment policy; instead, the Commission simply proposed to memorialize the Commission's existing policy in a *pro forma* agreement for affected systems.[2350] As a result, we decline to address arguments on the merits of the Commission's affected systems repayment policy in this final rule.

1245. With respect to the concerns raised by WAPA that it is unable to repay affected system interconnection customers due to limitations based on its federal status, we decline to rule on the specifics of individual transmission provider circumstances and instead find that such concerns are better raised in a compliance proceeding, including such a proceeding with a reciprocity tariff filing, if WAPA chooses to file one.

1246. In response to requests for clarification from Southern, we clarify that, consistent with the Commission's findings in Order No. 2003, we are not changing our policy

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No. 2003-C, 111 FERC ¶ 61,401 at P 13; *NARUC v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007) (affirming the Commission's conclusions); *W. Mass. Elec. Co. v. FERC,* 165 F.3d 922, 927 (D.C. Cir. 1999).

[2349] AECI Initial Comments at 9; Duke Southeast Utilities Initial Comments at 21-22, 26; EEI Initial Comments at 18-19; North Carolina Commission and Staff Initial Comments at 6; PPL Initial Comments at 21; Tri-State Initial Comments at 21-22; U.S. Chamber of Commerce Initial Comments at 11-12; Xcel Initial Comments at 40.

[2350] *See* Order No. 2003, 104 FERC ¶ 61,103 at PP 738-739; *see also pro forma* LGIA art. 11.4.

requiring the interconnection customer, at its expense, to install, operate, and maintain system protection facilities as a part of its generating facility or its interconnection facilities.[2351] Also in response to Southern and consistent with the Commission's findings in Order No. 2003, transmission providers may make a filing to the Commission proposing an incremental rate to the affected system interconnection customer, as more fully described in Order Nos. 2003-A and 2003-B,[2352] if native load and existing transmission customers are not being held harmless, though we reiterate that the transmission provider bears the full burden of showing that any such proposal is just, reasonable, and not unduly discriminatory or preferential and is appropriate under the circumstances.[2353]

1247. We adopt Tri-State's suggested revisions to proposed article 3.2.2.1 of the *pro forma* affected system facilities construction agreement regarding the terms for repayment of affected system network upgrades. Consistent with existing *pro forma* LGIA provisions,[2354] the parties may mutually agree to a repayment schedule for all applicable costs associated with affected system network upgrades, with complete

[2351] *Pro forma* LGIA art. 9.7.4.1; *see also* Order No. 845, 163 FERC ¶ 61,043 at P 371.

[2352] Order No. 2003-A, 106 FERC ¶ 61,220 at P 586; Order No. 2003-B, 109 FERC ¶ 61,287 at P 56.

[2353] Order No. 2003-B, 109 FERC ¶ 61,287 at P 56.

[2354] *Pro forma* LGIA art. 11.4.1.

repayment not to exceed 20 years from the commercial operation date of the affected system interconnection customer's generating facility.

1248. We decline to adopt additions to proposed article 4.1 (Provision of Security) of the *pro forma* affected system facilities construction agreement suggested by PacifiCorp that would add additional security posting requirements, to the extent that costs to construct affected system network upgrades increase.[2355] Proposed article 4.1 is consistent with security provisions outlined in *pro forma* LGIA article 11.5 (Provision of Security), and we find that such provisions should be consistent across both the *pro forma* affected system facilities construction agreement and the *pro forma* LGIA. We also find that the security provision requirements are already sufficiently clear in article 4.1 of the *pro forma* affected system facilities construction agreement. Specifically, article 4.1 of the *pro forma* affected system facilities construction agreement provides that "security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Affected System Network Upgrades."

1249. In response to comments from PPL asserting that affected system interconnection customers should be responsible for meeting the affected system transmission provider's creditworthiness requirements,[2356] because the *pro forma* affected system facilities construction agreement is an agreement between the affected system transmission provider and the affected system interconnection customer, we clarify that affected

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[2355] PacifiCorp Initial Comments at 37.

[2356] PPL Initial Comments at 20.

system interconnection customers are obligated to meet the affected system transmission provider's creditworthiness and security requirements. We note that this is consistent with the parallel requirement for interconnection customers to meet the creditworthiness and security requirements of the host transmission provider outlined in *pro forma* LGIA article 11.5.1.

1250. We revise proposed article 5.1(b) of the *pro forma* affected system facilities construction agreement, consistent with PacifiCorp's suggestion, to remove the requirement that a party will be in breach for failure to comply with a material term or condition of the agreement due to an inaccuracy in a representation, warranty, or covenant made in the agreement resulting in a breach under the agreement. We find that there is no reason why an inaccuracy should lead to a potential breach, or even a default, under the agreement. We note that the *pro forma* LGIA contains no similar provision.

1251. We revise proposed article 5.2.1, now article 5.3.1, of the *pro forma* affected system facilities construction agreement to extend the cure period for a breach from 30 calendar days to 60 calendar days and proposed article 5.2.2, now article 5.3.2, of the *pro forma* affected system facilities construction agreement to remove the additional cure period if the breach remains despite the occurrence of good faith steps. We find that the revision will simplify the cure requirements while providing breaching party with an extra 30 calendar days at the onset to cure its breach. We also revise article 5.3.2 to include a reference that if the breaching party defaults, then the non-defaulting party may terminate the agreement in accordance with article 6.2 (Termination) of the agreement. We further clarify article 5 of both the *pro forma* affected system facilities construction

agreement and the *pro forma* multiparty affected system facilities construction agreement that a failure to cure a breach of either agreement will also constitute a default.

1252. We decline to delete proposed article 6.4 (Survival of Rights) of the *pro forma* affected system facilities construction agreement, as suggested by Tri-State. Although Tri-State asserts that proposed article 6.4 should be deleted because it is duplicative of proposed article 2.4 (Survival),[2357] we find that the contents are sufficiently different to merit their separate inclusion. Specifically, article 2.4 provides for the survival of the *pro forma* affected system facilities construction agreement until all liabilities incurred prior to termination are fulfilled, whereas article 6.4 clarifies the scope of the rights of parties following termination to provide for final billing, enforcement of liabilities and confidentiality obligations, and for potential judicial or administrative action.

1253. In response to comments from Southern regarding updates to the confidentiality provisions contained in proposed article 8 (Confidentiality) of the *pro forma* affected system facilities construction agreement,[2358] we find that, because we are not proposing to revise the confidentiality provision set forth in the *pro forma* LGIA—instead, we are merely adopting it into the *pro forma* affected system facilities construction agreement—article 8, as adopted, is just and reasonable. Contrary to Southern's comments, the confidentiality provisions in article 8.1.7 of the *pro forma* affected system facilities construction agreement allow for confidential information to be destroyed, erased,

[2357] Tri-State Initial Comments at 34.

[2358] Southern Initial Comments at 19.

deleted or, as applicable, returned, not for such information to exclusively be "destroyed or returned."[2359] Thus, such language reflects the fact that most electronic information is stored in backup servers. Moreover, in response to Southern's concern that deleting information stored on backup servers is administratively difficult, we find that Southern has not provided any evidence or explained why this might be so.

1254. In response to MISO's contention that there is no need to list a commercial operation date for affected system network upgrades in Appendix A of the *pro forma* affected system facilities construction agreement,[2360] we agree and modify Appendix A, now Attachment A, to remove the commercial operation date from tables 1 and 3. However, we note that parties may find it useful to memorialize the commercial operation date for the affected system interconnection customer's generating facility because, under article 2.2.1 of the *pro forma* affected system facilities construction agreement, the parties to the agreement may alter the affected system facilities construction agreement by mutual consent if the in-service state date for the affected system network upgrades or the commercial operation date for the generating facility changes. To the extent MISO is concerned that there could be different commercial operation dates listed for affected system network upgrades in the LGIA and the affected system facilities construction agreement, the host transmission provider must update the commercial operation date for affected system network upgrades in the affected system

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[2359] *Id.*

[2360] MISO Initial Comments at 97.

interconnection customer's LGIA with the host system, to avoid discrepancies between the affected system facilities construction agreement and the LGIA.

1255. Finally, in response to comments from Eversource and ISO-NE,[2361] we clarify that these *pro forma* affected system agreements are distinct from intra-RTO/ISO agreements, like ISO-NE's RFA, which RTOs/ISOs may use to coordinate the construction of necessary network upgrades within multiple transmission owner service territories within the same RTO/ISO.[2362]

d. <u>Affected System Modeling and Study Assumptions</u>

i. <u>NOPR Proposal</u>

1256. As the Commission explained in the NOPR, when an interconnection customer submits an interconnection request, they must choose to be studied as ERIS or NRIS, depending on the level of deliverability they seek for the output of their generating facility. For interconnection customers seeking to deliver their generating facility's electric output using the existing firm or non-firm capacity of the transmission provider's system on an as-available basis, the interconnection customer will choose an ERIS study. An interconnection customer will choose an NRIS study when seeking to integrate their generating facility with the transmission provider's system (1) in a manner comparable to that in which the transmission provider integrates its generating facilities to serve native load customers or (2) in an RTO/ISO with market-based congestion management, in the

[2361] Eversource Initial Comments at 32; ISO-NE Initial Comments at 38.

[2362] Eversource Initial Comments at 31-32.

same manner as network resources.[2363] An NRIS study goes beyond the prerequisite ERIS study and uses stricter modeling standards[2364] to assess an interconnection request to ensure that the interconnection customer's electric output is deliverable to load in aggregate on the host transmission provider's system.[2365] Such a deliverability analysis varies regionally but can analyze anything from various stressed dispatch scenarios to an

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[2363] "Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis." *Pro forma* LGIP section 1; *pro forma* LGIA art. 1.

[2364] NOPR, 179 FERC ¶ 61,194 at P 210. The term "modeling standard" refers to the distribution factor threshold on a transmission element used by transmission providers, such that beyond this threshold an interconnection request will require network upgrades. For example, in SPP, if a transmission element is found to be overloaded in an interconnection study, and an NRIS interconnection request has over a 3% distribution factor on that element (3% being SPP's distribution factor threshold for NRIS requests), the requesting entity will be assigned network upgrades. SPP uses a 19.5% distribution factor threshold for ERIS requests. *See EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, 168 FERC ¶ 61,173 at P 17. A lower threshold indicates a stricter modeling standard because a smaller impact triggers network upgrades. Additionally, when conducting an affected system analysis, although some RTOs/ISOs (PJM and SPP, for example) use a modeling standard associated with the same level of service as requested on the host transmission provider's transmission system, the output of proposed generating facilities is always sunk into the host transmission provider's transmission system by reducing the output of other generating facilities on that system. *Id.* P 85.

[2365] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 768; Order No. 2003-A, 106 FERC ¶ 61,220 at P 500. Specifically, a transmission provider studying generating facility for NRIS would study the transmission system at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility operating at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with reliability criteria and procedures.

additional set of contingencies. As such, an NRIS study will likely identify more network upgrades to accommodate the interconnection of a generating facility than an ERIS study because NRIS provides a higher level of interconnection service than ERIS.

1257. As the Commission also explained in the NOPR, when a host transmission provider notifies an affected system operator of a possible impact on its system from an interconnection request in the host's queue, it must specify whether the interconnection customer requested ERIS or NRIS. Currently, there is no requirement for affected system transmission providers to apply either ERIS or NRIS modeling standards to study interconnection requests made on neighboring systems. For example, MISO uses ERIS studies for all affected system interconnection requests, while PJM and SPP use the modeling standard associated with the level of service requested on the host system. (They study ERIS requests as ERIS and NRIS requests as NRIS.)[2366]

1258. In the NOPR, the Commission preliminarily found that it was unjust and unreasonable for an affected system transmission provider to study interconnection requests on other transmission systems using NRIS modeling standards, regardless of the level of service requested on the host transmission system. The Commission noted that, unlike the host transmission provider with which the affected system interconnection customer will directly interconnect, an affected system transmission provider does not have a continuing obligation to operate its system so that NRIS resources will remain

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[2366] *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, 168 FERC ¶ 61,173 at PP 75-76.

deliverable on the host system. Without such an obligation, the Commission stated that an affected system interconnection customer may be required to construct significant network upgrades on the transmission provider's affected system, but not be fully deliverable due to curtailment or congestion on the affected system. The Commission was concerned that this could result in unjust and unreasonable rates by increasing the costs for the interconnection customer without a commensurate increase in service.

1259. The Commission proposed to require, under new *pro forma* LGIP section 9.6,[2367] the affected system transmission provider to study interconnection requests using ERIS modeling standards, regardless of the requested level of service on the host transmission provider's transmission system.[2368]

1260. The Commission also explained that if an affected system transmission provider believed that it was necessary to study an interconnection request that is requesting NRIS-level service using NRIS modeling standards, such a transmission provider could make a filing under FPA section 205. The Commission explained that it would evaluate such case-by-case FPA section 205 filings to determine whether they were just, reasonable, and not unduly discriminatory or preferential.[2369] The Commission noted that an affected system transmission provider making this type of filing should provide

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[2367] We note that under the NOPR proposal, this reform was in *pro forma* LGIP section 9.6; however, under the final rule, the reform is in *pro forma* LGIP section 9.7.

[2368] NOPR, 179 FERC ¶ 61,194 at P 211.

[2369] 16 U.S.C. 824d.

evidence indicating that using NRIS modeling standards in such a scenario would not treat similarly situated customers differently or afford similar treatment to dissimilar customers. In addition, this FPA section 205 filing could contain, for example, such supporting documentation as a reference to a NERC Reliability Standard violation, an operational concern such as over-duty breakers, fault current violations, impacts on transmission stability, increased loop flows, or other concerns that implicate any other critical reliability parameters.

1261. The Commission stated that a modeling standard would create consistency in the modeling standards used across all transmission regions.[2370] The Commission also stated that ERIS modeling standards generally reduce the number and cost of network upgrades identified and, by using ERIS modeling standards, interconnection customers would be subject to fewer late-stage cost increases, which would reduce the number of potential restudies and withdrawals thereby addressing the concerns that the Commission has preliminarily found to result in unjust, unreasonable, and unduly discriminatory or preferential Commission-jurisdictional rates. The Commission acknowledged that using a less stringent modeling standard may result in more frequent redispatch or curtailment by not fully capturing all the potential impacts of the interconnection generating facility(ies) on an affected system.[2371] Nevertheless, the Commission stated that it

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[2370] The Commission noted that, while this proposal would standardize the use of ERIS for affected system studies, individual transmission providers use different specific thresholds for ERIS studies. NOPR, 179 FERC ¶ 61,194 at P 212 n.292.

[2371] *Id.* P 213.

believed that these risks were limited in nature and any significant impact would be captured by an ERIS study, which would ensure that a proposed generating facility can safely connect the affected system under the expectation it will deliver its electric output using the existing firm or non-firm capacity of the affected system transmission provider's system on an as-available basis.

1262. The Commission sought comment on: (1) how to align the possibility for such case-by-case FPA section 205 filings with the required timeline for the affected system study and other deadlines proposed in the NOPR; (2) whether the proposed reform will adversely affect reliability for the affected system transmission provider or the host transmission provider; (3) the potential impact of requiring affected system transmission providers to use ERIS modeling standards when an interconnection customer seeks NRIS on the host transmission provider's system; and (4) whether there are modifications to this proposal that would reduce the likelihood of curtailment or redispatch on the affected system transmission provider's system without requiring the affected system interconnection customer to pay network upgrade costs that are not commensurate with the level of service it receives.[2372]

[2372] *Id.* PP 211, 213, 215.

ii. Comments

(a) Comments in Support

1263. Numerous commenters support the NOPR proposal.[2373] ELCON suggests that standardization of affected system modeling and assumptions furthers certainty and accountability, resulting in a more transparent, efficient, and cost-effective interconnection process.[2374] Some commenters argue that the NOPR proposal will reduce the identification and assignment of unnecessary affected system network upgrades under NRIS studies.[2375] MISO and Shell contend that ERIS modeling will adequately cover reliability for affected systems and that they have no significant concerns regarding unnecessary curtailment or redispatch on affected systems associated with ERIS modeling.[2376] Additionally, commenters contend that there is no need to use NRIS modeling standards when the affected system interconnection customer requests NRIS-level service on the host system because the generating facility's output will not be delivered to the affected system, and the NRIS standard serves the exclusive purpose of

[2373] ACE-NY Initial Comments at 9; AES Initial Comments at 21; Alliant Energy Initial Comments at 7; Clean Energy Associations Initial Comments at 48; Clean Energy Associations Reply Comments at 12; ELCON Initial Comments at 8; Enel Initial Comments at 67-68; Fervo Energy Initial Comments at 6; Invenergy Initial Comments at 44; MISO Initial Comments at 98; NextEra Initial Comments at 34; OMS Initial Comments at 17; Pattern Energy Initial Comments at 26; Pine Gate Initial Comments at 42; Shell Initial Comments at 31-32; UMPA Initial Comments at 6.

[2374] ELCON Initial Comments at 8.

[2375] Fervo Energy Initial Comments at 6; UMPA Initial Comments at 6.

[2376] MISO Initial Comments at 98; Shell Initial Comments at 33.

allowing interconnection customers to be designated as a network resource on the host system.[2377] Some commenters claim that the NOPR proposal will reduce the time required to conduct affected system study and construction processes, as well as the likelihood of withdrawals once the affected system necessary upgrades are identified.[2378]

(b) <u>Comments in Opposition</u>

1264. Some commenters oppose the NOPR proposal.[2379] AECI claims that, without increasing the granularity of the redispatch and curtailment process in real time to better understand the actual impact an affected system interconnection customer has on the affected system from a distribution factor standpoint, the NOPR proposal would produce disproportionate burdens by reducing otherwise economical and reliable generating facilities to accommodate resources that are outside an affected system transmission provider's control.[2380] Idaho Power asserts that the NOPR proposal may not sufficiently

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[2377] Fervo Energy Initial Comments at 6; Interwest Reply Comments at 18; Invenergy Initial Comments at 44; NextEra Initial Comments at 34; NextEra Reply Comments at 6; OMS Initial Comments at 17.

[2378] OMS Initial Comments at 17; Pine Gate Initial Comments at 42; Public Interest Organizations Initial Comments at 51.

[2379] AECI Initial Comments at 7; AEP Initial Comments at 34; Ameren Initial Comments at 23-24; Duke Southeast Utilities Initial Comments at 28; EEI Initial Comments at 19; Illinois Commission Initial Comments at 9; LADWP Initial Comments at 5; NRECA Initial Comments at 39; Southern Initial Comments at 4, 16; SPP Initial Comments at 20.

[2380] AECI Initial Comments at 7.

capture network upgrades that are jointly owned by multiple entities.[2381] Specifically, Idaho Power states that the host transmission provider "may not be the entity responsible for designing and constructing network upgrades and interconnection facilities; therefore, the affected party ERIS study may not provide sufficient details to be meaningful."[2382]

1265. Several commenters claim that the ERIS modeling requirement for affected systems will negatively impact reliability.[2383] AECI argues that incentivizing ERIS-only studies would fundamentally affect reliability by failing to address systemic *de minimis* issues that become material in the aggregate.[2384] Some commenters contend that, under the NOPR proposal, reliability issues will not arise until the operational time horizon, which could, as an example, result in an increase in transmission loading relief events and redispatch of network resources and native load.[2385] LADWP asserts that the dispatching assumptions of an interconnection request can make a significant difference to flow patterns in the host system, and parallel paths will inherently absorb the unscheduled flow intended for the host system.[2386] LADWP contends that, as the number of

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[2381] Idaho Power Initial Comments at 12.

[2382] *Id.*

[2383] AECI Initial Comments at 7; Illinois Commission Initial Comments at 9; Southern Initial Comments at 16-17.

[2384] AECI Initial Comments at 7.

[2385] Ameren Initial Comments at 24; LADWP Initial Comments at 5; PJM Reply Comments at 10; Southern Initial Comments at 16-17.

[2386] LADWP Initial Comments at 5.

interconnection requests continues to grow, these unscheduled flows will continue to increase and begin to affect systems downstream of the affected system, rather than just the local transmission system that the ERIS modeling standard is designed to evaluate. LADWP claims that the NOPR proposal would result in approval of generating facilities without identification of sufficient network upgrades to accommodate requested interconnection service, and affected system transmission providers would be responsible for maintaining reliability by developing operating procedures, capital projects, or performing curtailments from the additional stress of energy that is not being delivered to the affected system.

1266. AEP, SPP, and Xcel express concern that the proposed ERIS modeling standard may harm firm transmission service on the affected system.[2387] AEP, NRECA, and Xcel argue that affected system transmission providers should be able to use NRIS in affected system studies if the affected system interconnection customer is requesting NRIS-level service on the host transmission system to ensure the required level of deliverability.[2388] AEP states that, in the case that the interconnection customer is requesting to interconnect to a different RTO/ISO or is in a non-RTO/ISO, then an ERIS-only modeling standard could result in the failure to construct affected system network upgrades to mitigate

[2387] AEP Initial Comments at 34; SPP Initial Comments at 20; Xcel Initial Comments at 43.

[2388] AEP Initial Comments at 34; NRECA Initial Comments at 39; SPP Initial Comments at 20-21; Xcel Initial Comments at 43.

congestion and/or loop flow once the new generating facility commences operation, impacting loads that secured and paid for firm transmission service and/or NRIS.[2389]

1267. SPP is concerned that, if an affected system interconnection customer requests NRIS-level service on the host transmission system that grants deliverability rights without additional study procedures, an affected system may be exposed to impacts that it has not had an opportunity to evaluate under an ERIS modeling standard.[2390] As an example, SPP explains that SPP and MISO treat what constitutes firm transmission service differently, but SPP's current ability to conduct affected system studies under NRIS when the interconnection customer has requested NRIS on the host system allows for that difference. In response to SPP's concerns, NextEra argues that this issue appears to be a problem of SPP's own making based on how SPP implemented ERIS and NRIS on its own system and ignores that affected system interconnection customers are not seeking deliverability or to be deemed firm on SPP's transmission system through any sort of transmission service from SPP.[2391]

1268. Some commenters note that the proposal may not work in all scenarios.[2392] For instance, Clean Energy Associations state that this proposal may not be appropriate for

[2389] AEP Initial Comments at 34.

[2390] SPP Initial Comments at 20-21.

[2391] NextEra Reply Comments at 6-7.

[2392] AEP Initial Comments at 34; Clean Energy Associations Initial Comments at 48; SPP Initial Comments at 21-22; Xcel Initial Comments at 43.

non-RTO/ISO regions, if these impacts are not addressed through a coordinated transmission service study.[2393] Xcel believes that the use of ERIS modeling standards for affected system studies may be appropriate under a joint operating agreement or in areas where the impact may be evaluated and mitigated in the transmission service study process, but in other areas, if the impact will not be evaluated in the transmission service study process, it is appropriate for an affected system transmission provider to model the neighbor's NRIS requests based on the expected delivery point.[2394]

(c) Comments on Specific Proposal

1269. Some commenters ask the Commission to make changes to the NOPR proposal to mitigate the negative impacts they discuss in their comments. For example, some commenters recommend that, in addition to the ERIS modeling standard, the Commission should establish (or allow affected system transmission providers to establish) a distribution factor or impact threshold for affected system studies to ensure that affected system interconnection customers are not assigned unnecessary affected system network upgrades.[2395] NextEra recommends that the use of ERIS be included in the *pro forma* affected system study agreement to require any affected system

[2393] Clean Energy Associations Initial Comments at 48.

[2394] Xcel Initial Comments at 43-44.

[2395] AES Initial Comments at 8, 21; Clean Energy Associations Initial Comments at 48; Enel Initial Comments at 68; Pine Gate Initial Comments at 42; SEIA Initial Comments at 35.

transmission provider proposing to use NRIS rather than ERIS to file such agreement with the Commission on a non-conforming basis.[2396]

1270. Enel states that a critical interconnection issue not addressed in the NOPR is the lack of clarification of ERIS and NRIS-level service and how the different assumptions used by transmission providers significantly alter results.[2397] Enel explains that the wide variety of views on what rights interconnection service grants to an interconnection customer leads to confusion in the development of study practices and requirements, as well as the services and products a generating facility can provide. Enel requests that, in a final rule or a supplemental notice, the Commission should provide concrete direction regarding how these service types should be studied and what outcome an interconnection customer should receive for making the necessary transmission system improvements to obtain that interconnection service. NV Energy requests that affected system transmission providers and host transmission providers coordinate assumptions for affected system studies and update those assumptions quarterly after the affected system study has been issued to provide meaningful changes.[2398]

[2396] NextEra Initial Comments at 34.

[2397] Enel Initial Comments at 26-27.

[2398] NV Energy Initial Comments at 12.

1271. Some commenters note that a final rule should provide host transmission providers with flexibility to work with their neighboring regions to address modeling consistencies in transmission system representations across regions.[2399]

1272. Some commenters specifically support allowing transmission providers to use NRIS modeling standards for affected system studies pursuant to separate FPA section 205 filings, as proposed in the NOPR.[2400] Duke Southeast Utilities assert that the Commission should remove any negative repercussions, including any financial penalties or liability for breaching deadlines of the study process, for affected system transmission providers that seek to make such FPA section 205 filings.[2401]

1273. Several commenters argue that affected system transmission providers should be able to use NRIS when conducting affected system studies without requiring the NOPR's proposed FPA section 205 filing.[2402] A few commenters argue that the requirement to make an FPA section 205 filing to use NRIS modeling standards will create delays and is overly burdensome on affected system transmission providers.[2403] SPP claims that, as

[2399] Duke Southeast Utilities Initial Comments at 27-28; NYISO Initial Comments at 46.

[2400] AES Initial Comments at 21; Clean Energy Associations Initial Comments at 48; Fervo Energy Initial Comments at 6.

[2401] Duke Southeast Utilities Initial Comments at 27-28.

[2402] *Id.* at 28; AECI Initial Comments at 7; AEP Initial Comments at 34; Ameren Initial Comments at 23-24; EEI Initial Comments at 19; Illinois Commission Initial Comments at 9; LADWP Initial Comments at 5; NRECA Initial Comments at 39; Southern Initial Comments at 4, 16; SPP Initial Comments at 20.

[2403] AECI Initial Comments at 7; AEP Initial Comments at 34; Duke Southeast

proposed in the NOPR, an FPA section 205 filing to use NRIS modeling assumptions would require supporting documentation amounting to evidence that the affected system transmission provider could only obtain if it conducted a study using the standards of the heightened level of service, which it could not do absent the Commission's grant of a waiver to require such a study.[2404] Invenergy argues that the option for an FPA section 205 request to conduct an affected system study using NRIS criteria invites case-by-case disputes over modeling criteria, potentially delaying the affected system study process. Therefore, Invenergy argues that the Commission should clarify that any such filing must be limited to only the facts of an individual interconnection request.[2405]

1274. Xcel states that the Commission should: (1) remove the ERIS option in RTO/ISO markets and require all generating facilities in such markets to be deliverable; (2) curtail generating facilities that did not pay for long-term firm transmission service; or (3) convene a technical conference on this topic in this docket.[2406] Xcel explains that ERIS-only generating facilities in RTO/ISO markets may place a bid to sell into the market, and the ERIS-only generating facilities will be dispatched to the extent a bid clears, while in other areas, the ERIS-only generating facilities must acquire transmission service to be

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Utilities Initial Comments at 27; EEI Initial Comments at 19; LADWP Initial Comments at 5; MISO Initial Comments at 98; Southern Initial Comments at 16; SPP Initial Comments at 20.

[2404] SPP Initial Comments at 20.

[2405] Invenergy Initial Comments at 44-45.

[2406] Xcel Initial Comments at 16, 41-42.

delivered.[2407] Xcel concludes that ERIS service in RTO/ISO markets results in unjust and unreasonable rates and discriminatory treatment because ERIS-level generating facilities do not bear the costs necessary to ensure that they are deliverable to load. Xcel claims that: (1) the affected system transmission provider should not have to assume it will redispatch its own network resources to accommodate an affected system interconnection customer taking NRIS-level service; (2) the affected system's network resources paid for and expect to receive firm transmission service; and (3) there is no process for a host transmission provider to require an affected system transmission provider to redispatch its transmission system to accommodate a generating facility on the host system under the *pro forma* tariff.[2408]

1275. NRECA asserts that the final rule should allow a "transmission customer" to propose a different standard through an FPA section 206 complaint.[2409] NextEra and MISO suggest that, to avoid delays in the interconnection process, any affected system transmission provider submitting an FPA section 205 filing to use NRIS modeling in an affected system study should proceed with the affected system study, using both the ERIS and NRIS standards, and then the appropriate results could be used based on the outcome of the FPA section 205 proceeding.[2410] MISO also encourages the Commission to

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[2407] *Id.* at 15.

[2408] *Id.* at 43.

[2409] NRECA Initial Comments at 40.

[2410] MISO Initial Comments at 98; NextEra Initial Comments at 34.

recognize that this FPA section 205 filing process will add length and delay to the affected system study process, which further compounds and demonstrates the problems with the Commission's automatic penalty proposal.[2411]

iii. Commission Determination

1276. We adopt the NOPR proposal, with modification, to add section 9.7 to the *pro forma* LGIP to require affected system transmission providers to study all affected system interconnection requests using ERIS modeling standards.[2412] We decline to adopt the NOPR proposal to expressly acknowledge in *pro forma* LGIP section 9.7 that an affected system transmission provider may submit an FPA section 205 filing to request to study an affected system interconnection customer using NRIS on a case-by-case basis.

1277. We find that the use of ERIS in affected system studies is just and reasonable, given that the affected system transmission provider has no obligation to continually ensure deliverability for an affected system interconnection customer that has obtained NRIS on its host system. An NRIS study goes beyond the prerequisite ERIS study and uses stricter modeling standards to assess an interconnection request to ensure that the interconnection customer's electric output is deliverable to load in aggregate on the host

[2411] MISO Initial Comments at 98.

[2412] In relevant part, *pro forma* LGIP section 9.7 states: "Transmission Provider must study an Affected System Interconnection Customer using the Energy Resource Interconnection Service modeling standard used for Interconnection Requests on its own Transmission System, regardless of the level of interconnection service that Affected System Interconnection Customer is seeking from the host transmission provider with whom it seeks to interconnect."

transmission provider's transmission system.[2413] We find that the use of ERIS for affected system studies is consistent with Order No. 2003 because interconnection is separate from the deliverability component of transmission service.[2414]

1278. We also find that this requirement is likely to prevent an affected system interconnection customer from being required to construct significant network upgrades on the transmission provider's affected system, but not being deliverable due to curtailment or congestion on the affected system. Without this reform, rates would continue to be unjust and unreasonable because an affected system interconnection customer would face increased costs without a commensurate increase in service, as explained in the NOPR. This mismatch between costs and services received would occur because the affected system transmission provider has no obligation to ensure that the output from the affected system interconnection customer's generating facility is deliverable on the affected system and could lead to curtailment of the generating facility, or there could be congestion on the affected system preventing deliverability of the generating facility's output.

[2413] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 768; Order No. 2003-A, 106 FERC ¶ 61,220 at P 500. Specifically, a transmission provider studying a generating facility for NRIS would study the transmission system at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility operating at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with reliability criteria and procedures.

[2414] Order No. 2003, 104 FERC ¶ 61,103 at P 118; Order No. 2003-A, 106 FERC ¶ 61,220 at P 113.

1279. We also find that, if the affected system transmission provider were able to study affected system interconnection customers under an NRIS standard, it could require affected system interconnection customers to pay significant upfront costs in order to construct the required affected system network upgrades, which could lead to late-stage interconnection request withdrawals as interconnection customers will not receive affected system study results until late in the interconnection process. An ERIS standard ensures that the assigned affected system network upgrade costs will likely be lower and that affected system interconnection customers assigned affected system network upgrades will be less likely to withdraw at a late stage. This standard will help prevent the cascading restudies that commenters have observed[2415] and will ensure that the interconnection process operates more efficiently.

1280. We also find that the use of ERIS in affected system study processes across all transmission provider regions will create consistency and provide transparency for affected system interconnection customers. Currently, similarly situated interconnection customers requesting NRIS on their host transmission systems could have disparate impacts on affected systems that use different modeling standards, and these interconnection customers could be assigned dramatically different affected system network upgrade costs due to those varying modeling standards, without any factual or service differences to justify the discriminatory treatment. Thus, the consistent application of ERIS in affected system studies across all transmission providers' study

[2415] OMS Initial Comments at 17; Pine Gate Initial Comments at 42.

processes will ensure that all affected system interconnection customers are studied similarly.[2416] As such, we agree with commenters that the use of ERIS on all affected system interconnection requests will increase certainty and transparency.[2417]

1281. We find outside the scope of this final rule Xcel's request that the Commission require all generating facilities in RTO/ISO markets to be deliverable and its claim that ERIS-level generating facilities do not bear the costs necessary to ensure that they are deliverable to load.[2418] We are not proposing in this final rule to alter how an interconnection customer in an RTO/ISO requests its type of interconnection service on the host system (i.e., ERIS or NRIS); rather, we are standardizing how an affected system transmission provider studies an affected system interconnection request.

1282. Regarding AECI's claim that the NOPR proposal would produce disproportionate burdens by necessitating curtailment from economical and reliable generating facilities to accommodate generating facilities on a different transmission system unless overall granularity of the redispatch and curtailment process is increased in real time, we find no evidence of this concern, from AECI or otherwise.[2419] Rather, AECI appears concerned

[2416] Order No. 2003, 104 FERC ¶ 61,103 at P 11 (stating that a standard set of interconnection procedures will, among other things, expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable).

[2417] ELCON Initial Comments at 8; Fervo Energy Initial Comments at 6; UMPA Initial Comments at 6.

[2418] Xcel Initial Comments at 15-16, 41-42.

[2419] AECI Initial Comments at 7.

that generating facilities on its transmission system may be redispatched and curtailed, which we have acknowledged may occur.[2420] Additionally, we note the transmission loading relief procedures set the priority for curtailing generating facilities as necessary, and this final rule is not revising those procedures. Finally, to the extent that the costs associated with increasing the overall granularity of real-time models is less than any hypothetical increase in curtailment and redispatch costs, a transmission provider may increase the real-time granularity of its model.

1283. Further, we find that Idaho Power has not adequately explained how this reform will result in insufficiently identifying network upgrades that are jointly owned by multiple entities.[2421] Moreover, even if this were a valid concern, we find that this concern would be equally present regardless of the modeling standard (i.e., ERIS or NRIS) used to conduct the affected system study.

1284. As discussed in the NOPR proposal, using a less stringent modeling standard may result in more frequent redispatch or curtailment by not fully capturing all the potential impacts of the affected system interconnection customer's generating facility(ies) on an affected system. Based on the record, we continue to find that these risks are limited in nature, particularly in non-RTO/ISO regions where interconnection service does not, by itself, allow a generating facility's power to flow. In non-RTO/ISO regions, power can only flow from a generating facility once transmission service has been requested and

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[2420] NOPR, 179 FERC ¶ 61,194 at P 213.

[2421] Idaho Power Initial Comments at 12.

granted. For example, once point-to-point transmission service has been requested to enable a particular generating facility's power to flow, either by the generating facility itself or its power sale customer, *pro forma* open access transmission tariff section 21 (Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities) provides a process similar to the affected system process in the *pro forma* LGIP. In summary, *pro forma* open access transmission tariff section 21 makes the transmission customer responsible for obtaining any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of utilities other than the directly connected transmission provider, but requires that transmission provider to undertake reasonable efforts to assist in that effort. This means that affected systems will have another opportunity to study the impact of the interconnection customer's generating facility in the context of this transmission service request, whether a new point-to-point transmission service request or designation as a new network resource under an existing transmission customer's network integration transmission service, before any power can flow from the generating facility.

1285. Moreover, we find that any significant impact would generally be captured by an ERIS study, which would ensure that any reliability impacts on the affected system are mitigated to accommodate the interconnection of the affected system interconnection customer's proposed generating facility to the host system. That ERIS adequately studies an affected system interconnection customer's interconnection request for its reliability

impacts on the affected system is evidenced by MISO's use of only ERIS in affected system studies without adverse reliability impacts.[2422]

1286. Regarding AECI's claim that using only ERIS in affected system studies may result in increased *de minimis* impacts,[2423] we are not setting the implementation of the ERIS standard. Rather, each transmission provider determines its own implementation of that standard, which could include a *de minimis* threshold that is best for its region. The Commission has found that, if consistently applied, it is reasonable for interconnection customers to not bear cost responsibility for *de minimis* impacts on transmission facilities based on a threshold.[2424] Additionally, we expect that any overloads in the models due to the accumulation of *de minimis* impacts will ultimately be assigned, pursuant to the transmission provider's tariff, when an interconnection customer triggers the need for a network upgrade or when the transmission provider's reliability transmission planning process identifies the need for mitigation.

1287. We disagree with LADWP that the use of ERIS by an affected system transmission provider will result in approval of generating facilities with insufficient network upgrades identified.[2425] As discussed above, we find that, in general, the use of

[2422] MISO Initial Comments at 98.

[2423] AECI Initial Comments at 7.

[2424] *Tenaska Clear Creek Wind, LLC v. Sw. Power Pool, Inc.*, 180 FERC ¶ 61,160, at P 99 (2022).

[2425] LADWP Initial Comments at 5.

ERIS is sufficient for affected system studies to prevent reliability issues from occurring on the affected system. Moreover, as noted earlier, in non-RTO/ISO regions, power can only flow from a generating facility once transmission service has been requested and granted, meaning that affected systems will have another opportunity to study the impact of the interconnection customer's generating facility in the context of the associated transmission service request before any power can flow from that generating facility as explained above.

1288. Similarly, we find that commenters' concerns about harm to firm transmission service and cost shifting when using ERIS in affected system studies are misplaced because those concerns do not arise until the interconnection customer seeks to deliver power from its generating facility to a customer, which outside of RTO/ISO regions can only happen once transmission service is separately secured.[2426] In Order No. 2003, the Commission found that interconnection service is separate from the delivery component of transmission service, and, in the majority of circumstances, interconnection alone is unlikely to affect the reliability of an affected system transmission provider's transmission system.[2427] Additionally, the Commission found that holding new interconnection customers responsible for network upgrades to all interconnected systems, including not only the transmission system to which the generating facility

[2426] AEP Initial Comments at 34; NRECA Initial Comments at 39; SPP Initial Comments at 20-21; Xcel Initial Comments at 43.

[2427] Order No. 2003, 104 FERC ¶ 61,103 at P 118; Order No. 2003-A, 106 FERC ¶ 61,220 at P 113.

interconnects, but other, more distant transmission systems as well would create an unreasonable obstacle to the construction of new generation.[2428] As such, if an affected system interconnection customer subsequently seeks deliverability on either the host system or an affected system and submits a transmission service request to either the host transmission provider or the affected system transmission provider, the affected system transmission provider will have the opportunity to study the request and potentially require the construction of additional network upgrades on the affected system to accommodate deliverability. Therefore, we find that being assigned significant affected system network upgrades under an NRIS study without the obligation for the affected system transmission provider to ensure that the output from an affected system interconnection customer's generating facility is integrated on the affected system similar to generating facilities that serve the affected system transmission provider's native load customers or network resources results in unjust and unreasonable rates by increasing the cost for affected system interconnection customers without a commensurate increase in service.[2429]

[2428] Order No. 2003, 104 FERC ¶ 61,103 at P 120.

[2429] As stated in Section III.A.1, the *pro forma* LGIP defines NRIS service as "an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service." *Pro forma* LGIP section 1.

1289. Regarding claims that affected system transmission providers would need to develop operating procedures or capital projects or perform curtailments due to the additional stress on affected systems caused by affected system interconnection requests being studied under the ERIS modeling standard,[2430] we find these claims to be speculative and that affected system studies are designed to ensure that an affected system interconnection customer's proposed generating facility can reliably connect to the host system without adversely impacting an affected system and are not meant to ensure deliverability on either the host or affected system. As mentioned above, an affected system transmission provider has no obligation to ensure that an affected system interconnection request is fully deliverable.

1290. We are unpersuaded by arguments that the NOPR proposal may not work in all scenarios[2431] and note that commenters did not provide specific examples of how the proposal would not work under the Commission's *pro forma* LGIP process. Several commenters raise concerns that, although the use of ERIS may work in regions with joint operating agreements or coordinated transmission service studies, the use of ERIS for all affected system studies may not be appropriate if an affected system transmission provider's transmission service studies do not identify all impacts. Once again, in adopting the ERIS requirement for affected system transmission providers, we find that

[2430] LADWP Initial Comments at 5.

[2431] AEP Initial Comments at 34; Clean Energy Associations Initial Comments at 48; SPP Initial Comments at 20-21; Xcel Initial Comments at 43.

ERIS is sufficient to capture reliability impacts of affected system interconnection requests on the affected system. We do not address whether individual transmission providers have adequate transmission service studies. If a transmission provider believes that changes are needed to better consider the deliverability of transmission service on its transmission system or with its neighboring transmission systems, nothing in this final rule prevents transmission providers from addressing those concerns.

1291. We decline requests for the Commission to set modeling standards, to require transmission providers to include their modeling standards in their tariffs, or to provide direction on how ERIS and NRIS should be studied and what service the interconnection customer should receive, and to require neighboring transmission providers to coordinate assumptions and update those assumptions quarterly.[2432] We find these requests to be outside the scope of the final rule.

1292. Although some commenters request flexibility on whether to use ERIS or NRIS in conducting an affected system study,[2433] we find such a request is essentially a request to maintain the status quo, which, as discussed above, results in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential and prevents

[2432] AES Initial Comments at 8, 21; Clean Energy Associations Initial Comments at 48; Enel Initial Comments at 27, 68; NV Energy Initial Comments at 12; Pine Gate Initial Comments at 42; SEIA Initial Comments at 35.

[2433] Duke Southeast Utilities Initial Comments at 27-28; NYISO Initial Comments at 46.

interconnection customers from interconnecting in a reliable, efficient, transparent, and timely manner.

1293. We decline to adopt the proposal stating that an affected system transmission provider may make an FPA section 205 filing to request use of an NRIS modeling standard in affected system studies. We find that there is no need to expressly provide for the availability of an FPA section 205 filing in *pro forma* LGIP section 9.7 because transmission providers always have the right to submit an FPA section 205 filing.

3. Optional Resource Solicitation Study

a. NOPR Proposal

1294. In the NOPR, the Commission explained that resource solicitation processes inspire a number of interconnection requests, but in most cases, state agencies and LSEs implementing state mandates do not have the opportunity to request dedicated studies themselves.[2434]

1295. The Commission proposed to revise the *pro forma* LGIP to require transmission providers to allow resource planning entities, i.e., any entity required to develop a resource plan or conduct a resource solicitation process, including a state entity or LSE, to initiate an optional resource solicitation study.[2435]

1296. Under the NOPR proposal, the resource planning entity would identify the valid interconnection requests associated with its qualifying resource solicitation process or

[2434] NOPR, 179 FERC ¶ 61,194 at P 211.

[2435] *Id.* P 223.

qualifying resource plan and request that the transmission provider study several combinations of those interconnection requests in a resource solicitation study.[2436]

1297. The Commission clarified that under this proposal, the resource planning entity would not receive a queue position: interconnection customers would maintain their queue position obtained through the cluster request window and proceed through the regular interconnection queue alongside all other customers.[2437]

1298. The Commission proposed that the transmission provider must evaluate each combination of interconnection requests submitted by the resource planning entity as a group, in the same manner it will perform cluster studies under the proposed *pro forma* LGIP.[2438] The Commission proposed a 135-calendar day time limit on the optional resource solicitation study (compared to 150 calendar days for the cluster study).

1299. The Commission sought comment on: (1) the NOPR proposal to explicitly include state agencies that are required to develop a resource plan or conduct a resource solicitation process in the definition of a resource planning entity; (2) whether other entities should qualify as resource planning entities and therefore be able to request initiation of an optional resource solicitation study, and, if so, what impact, if any, their inclusion would have on the efficiency of the interconnection process and whether their inclusion would raise concerns of undue discrimination or preference; (3) whether the

[2436] *Id.* P 224.

[2437] *Id.* P 226.

[2438] *Id.* P 233.

proposed optional resource solicitation study raises any confidentiality concerns, including whether the optional resource solicitation study report could be posted on the transmission provider's OASIS before the qualifying solicitation process has concluded; and (4) what, if any, challenges multistate transmission providers—in particular, those RTOs/ISOs that serve large, multi-state areas—may face regarding study timing, multiple concurrent studies, or other issues in offering an optional resource solicitation study option, and any proposals to mitigate such challenges.[2439]

b. Comments

i. Comments in Support

1300. Many commenters support the NOPR proposal and note that the ability to gather holistic information on a range of resource mix scenarios from transmission providers would support efforts by states and other resource planning entities to meet policy objectives.[2440] The North Dakota Commission notes that resource solicitation studies could help improve coordination and make state-level, bottom-up resource planning processes more efficient and cost-effective.[2441] Similarly, Ørsted argues that resource

[2439] *Id.* PP 236-237.

[2440] Clean Energy States Initial Comments at 9; Colorado Commission Reply Comments at 2; Consumers Energy Initial Comments at 8; EEI Initial Comments at 5-6; Illinois Commission Initial Comments at 11; Iowa Commission Initial Comments at 6; NARUC Initial Comments at 25; NESCOE Initial Comments at 17; New Jersey Commission Initial Comments at 16-17; North Carolina Commission Initial Comments at 26; Northwest and Intermountain Initial Comments at 15; Ørsted Initial Comments at 15; OPSI Initial Comments at 7; Public Interest Organizations Initial Comments at 37-38.

[2441] North Dakota Commission Initial Comments at 7.

solicitation studies have the potential to reduce the uncertainty involving the interconnection cost portion of future state-sponsored resource solicitations.[2442]

ii. Comments in Opposition

1301. AES states that it does not believe reforms on this issue should be part of the final rule but does not oppose transmission providers submitting optional resource solicitation study proposals to the Commission pursuant to separate FPA section 205 filings after consultation with stakeholders.[2443]

1302. AEP disagrees with the Commission's conclusion that failure to provide for a resource solicitation process leads to unjust and unreasonable rates.[2444] AEP argues that this reasoning only applies to "entities required to conduct a resource plan or resource solicitation process" and that, accordingly, there is no legal basis to "solve" the problem through a nationwide mandate, as transmission providers with no LSEs that are required to "conduct a resource plan or resource solicitation process" do not need to amend their tariffs to include the optional resource solicitation study proposal. AEP asserts that there is no evidence that LSEs in RTOs/ISOs need the optional resource solicitation study process to perform IRPs efficiently and reach appropriate procurement decisions. AECI argues that resource planning entities should maintain discretion over their portfolios, and that the Commission lacks jurisdiction to mandate deployment of any particular resource

[2442] Ørsted Initial Comments at 15.

[2443] AES Initial Comments at 22.

[2444] AEP Initial Comments at 39-40.

or to require transmission providers to provide preferential treatment towards any specific technology.[2445]

1303. Several commenters argue that the proposed optional resource solicitation study is unnecessary, particularly in regions such as PJM and MISO, which have existing or proposed processes for considering state objectives.[2446]

1304. CAISO and SPP argue that the proposed optional resource solicitation study may create uncertainty regarding the cost and timing of interconnecting to the transmission system.[2447] CAISO asserts that it is impossible to provide meaningful cost data to interconnection customers until the transmission provider knows precisely the entire make-up of the study cluster.[2448]

1305. Several commenters question the efficacy of the resource solicitation study proposal.[2449] PJM argues that, because the study would include only a subset of the clustered interconnection requests, the results would not be indicative of the outcome when considering the entire cluster, and would not provide information upon which

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[2445] AECI Initial Comments at 8.

[2446] Dominion Initial Comments at 39; Dominion Reply Comments at 24; Indicated PJM TOs Initial Comments at 51; MISO Initial Comments at 9, 98-102; MISO Reply Comments at 11; National Grid Initial Comments at 39; OMS Initial Comments at 18.

[2447] CAISO Initial Comments at 30; SPP Initial Comments at 22.

[2448] CAISO Initial Comments at 31.

[2449] AEE Initial Comments at 35; Enel Initial Comments at 71; Indicated PJM TOs Initial Comments at 50.

resource planning entities could act or base decisions.[2450] Enel and Indicated PJM TOs argue that the studies would not be expected to yield a reliable estimate of the total costs of the portfolio of resources being contemplated by the resource planner.[2451] Similarly, Indicated PJM TOs argue that optional studies will divert scarce resources away from curing the fundamental problem, arguing that such studies may not be valuable to resource planners because they would be conducted in a vacuum, would not account for other interconnection requests, and would not necessarily lead to the most efficient combination of resources.[2452]

1306. Some commenters assert that prospective interconnection customers will have an incentive to lodge speculative interconnection requests antithetical to the desired streamlining of the *pro forma* LGIA and *pro forma* LGIP process contemplated by the NOPR.[2453] APPA-LPPC comment that, to the extent that the generating facilities associated with interconnection requests are competing in a resource solicitation in which they may not be selected, such interconnection requests could constitute the kind of speculative interconnection request that the NOPR otherwise discourages.[2454]

[2450] PJM Initial Comments at 50.

[2451] Enel Initial Comments at 71; Indicated PJM TOs Initial Comments at 50.

[2452] Indicated PJM TOs Initial Comments at 50.

[2453] AECI Initial Comments at 8; Enel Initial Comments at 69.

[2454] APPA-LPPC Initial Comments at 27.

1307. Several commenters argue that the optional resource solicitation study will result in inefficiencies and delays that degrade the quality of the main cluster study.[2455] Several commenters express concern that adding optional resource solicitation studies as a *pro forma* LGIP requirement would hinder the Commission's goal of increasing the speed of processing interconnection requests, arguing that the additional study requirements are time consuming and would require significant resources to complete.[2456] Enel states that, because a transmission provider would be required to evaluate six full cluster studies (i.e., one standard plus five sensitivities) with different combinations of generating facilities, the optional resource solicitation study would inevitably lead to delays, restudies, late-stage withdrawals, errors, and increased potential for inadequate consideration of lower cost and alternative mitigations.[2457] The Colorado Commission argues that the NOPR proposal could materially delay the clean energy transition in Colorado given

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[2455] *Id.*; AECI Initial Comments at 8; Bonneville Initial Comments at 22; CAISO Initial Comments 30-31; CREA and NewSun Reply Comments at 55; Dominion Initial Comments at 39; Enel Initial Comments at 69; Illinois Commission Initial Comments at 11; NARUC Initial Comments at 31; NextEra Initial Comments at 35; NYISO Initial Comments at 46; PJM Initial Comments at 5-6.

[2456] Bonneville Initial Comments at 22; CAISO Initial Comments 30-31; CREA and NewSun Reply Comments at 55; Enel Initial Comments at 69; Illinois Commission Initial Comments at 11; NARUC Initial Comments at 31; NextEra Initial Comments at 35; NYISO Initial Comments at 46; PJM Initial Comments at 6; SEIA Reply Comments at 18, 21; SPP Initial Comments at 22.

[2457] Enel Initial Comments at 69-71.

interconnection scarcity concerns if it required the elimination of resource solicitation clusters as currently implemented by the Colorado utilities.[2458]

1308. Some commenters question whether transmission providers can realistically manage interconnection cluster studies and perhaps multiple optional resource solicitation studies at the same time.[2459] Indicated PJM TOs state that the ability for any resource planning entity to initiate the resource solicitation study without warning at any time would be especially burdensome.[2460] MISO warns that multiple resource planning entities could request an optional study with different combinations, requiring MISO to perform numerous iterations of its system impact studies.[2461] Several commenters argue that instituting an additional study will put further strain on transmission providers' limited staff resources.[2462] Bonneville, WAPA, and NRECA assert that most small transmission providers are not staffed or organized to accomplish the work discussed by the Commission.[2463]

[2458] Colorado Commission Reply Comments at 3.

[2459] Indicated PJM TOs Initial Comments at 50; MISO Initial Comments at 101-102; Northwest and Intermountain Initial Comments at 16-17; NRECA Initial Comments at 41-42; PJM Initial Comments at 6.

[2460] Indicated PJM TOs Initial Comments at 50; Indicated PJM TOs Reply Comments at 18.

[2461] MISO Initial Comments at 102.

[2462] Dominion Initial Comments at 39; Indicated PJM TOs Initial Comments at 50; National Grid Initial Comments at 38-39; NYISO Initial Comments at 46; PJM Initial Comments at 6; SEIA Initial Comments at 36.

[2463] Bonneville Initial Comments at 22; WAPA Initial Comments at 14; NRECA

1309. Several commenters caution the Commission that the optional resource solicitation studies could be costly.[2464] MISO contends that mandating a new study activity without a corresponding study deposit may result in a situation where study deposit funds run out, halting interconnection studies until more funds are provided and leading to interconnection queue delays.[2465] NRECA also argues that requiring both the optional informational interconnection studies and the optional resource solicitation studies increase costs for transmission customers.[2466] SEIA argues that imposing an optional resource solicitation process in the early stages of the interconnection process, before interconnection customers receive the cost estimates of their network upgrades, means that the results from the study may not accurately reflect the costs of the network upgrades for the resources in the study.[2467] Enel argues that, because the resource planning entity selects generating facilities for scenarios without any knowledge of interconnection results, it is possible that the selected generating facilities will end up being built despite large upgrade costs.[2468]

Initial Comments at 41-42.

[2464] Clean Energy Associations Initial Comments at 51; Illinois Commission Initial Comments at 11; MISO Initial Comments at 103.

[2465] MISO Initial Comments at 103.

[2466] NRECA Initial Comments at 41-42.

[2467] SEIA Reply Comments at 18-19.

[2468] Enel Initial Comments at 72.

1310. Several commenters contend that the proposal is unjust, unreasonable, and unduly discriminatory or preferential because it gives special treatment to generating facilities selected to fulfill a resource plan without full consideration of interconnection upgrades.[2469] Several commenters are concerned that this proposal could allow vertically integrated transmission providers or LSEs to use the process in a way that would inappropriately favor the interconnection of company-owned resources.[2470] NARUC and SEIA explain that an LSE could have a transmission provider identify cost-saving interconnection options through the optional resource solicitation study for company-owned resources but exclude non-company-owned resources from the analysis, thus tipping the cost evaluation in favor of the company's resources.[2471] Likewise, Interwest and EPSA are concerned that priority in interconnection queue processing for interconnection requests selected in a resource plan and under contract with a utility may provide competitive advantages for vertically integrated utilities because of their control

[2469] *Id.* at 68, 72; AEE Initial Comments at 35-36; EPSA Initial Comments at 12; Interwest Initial Comments at 9; Interwest Reply Comments at 8; MISO Initial Comments at 98; OMS Initial Comments at 18; PJM Initial Comments at 50-51; SEIA Reply Comments at 19-20.

[2470] AEE Initial Comments at 36; CREA and NewSun Initial Comments at 89; EPSA Initial Comments at 11-12; Interwest Initial Comments at 9-10; NARUC Initial Comments at 26-27; Northwest and Intermountain Initial Comments at 15-16; Public Interest Organizations Initial Comments at 41; SEIA Initial Comments at 36.

[2471] NARUC Initial Comments at 26-27; SEIA Initial Comments at 36; SEIA Reply Comments at 20.

over the selection of projects and the identification and timing of the installation of network upgrades.[2472]

1311. SEIA also argues that an optional resource solicitation study in situations where there is a commercial readiness requirement presents numerous opportunities for a utility to discriminate against independent power producers in favor of that utility's own generation.[2473] AEP argues that, in multi-state RTOs/ISOs, the proposal facially discriminates against LSEs that are not eligible resource planning entities or are located in states that are not eligible resource planning entities themselves, and shifts key RTO/ISO resources away from such entities.[2474] In RTOs/ISOs that allow bilateral capacity procurement, AEP argues that the proposal likewise discriminates between LSEs with qualifying resource planning entities (which may well be themselves) and those without.

1312. Multiple commenters argue that the proposed requirement to perform an optional resource solicitation study in multiple states imposes a considerable burden on RTOs/ISOs without providing meaningful benefits.[2475] PJM argues that requiring it "to

[2472] EPSA Initial Comments at 12; Interwest Initial Comments at 9-10.

[2473] SEIA Initial Comments at 36.

[2474] AEP Initial Comments at 37-38.

[2475] *Id.* at 36-37; AES Initial Comments at 22; CAISO Initial Comments at 31; ClearPath Initial Comments at 9; Dominion Initial Comments at 39; MISO Initial Comments at 105; NextEra Initial Comments at 35; PJM Initial Comments at 51; SEIA Reply Comments at 21; WAPA Initial Comments at 15.

serve as a de facto consultant" to resource planning entities in addition to its efforts to expedite and process the country's largest interconnection queue would require PJM to take on a role beyond its authority as a transmission provider.[2476] Similarly, Indicated PJM TOs argue that there is no justification for requiring transmission providers to provide resource solicitation studies when consultants could do so.[2477]

1313. The North Dakota Commission suggests that the Commission should consider whether the proposal potentially allows cost-shifting from states or localities with significant resource build out mandates to other states within the RTO/ISO and how to mitigate such unjust cost-shifting.[2478] Similarly, Interwest cautions that, in bilateral and RTO/ISO markets, requiring a ranking in priority between interconnection requests may result in setting up competition between the utilities, with each vying for space on the constrained system.[2479]

1314. Tri-State adds that there are "timing issues" regarding the optional resource solicitation study, as it does not align with the electric resource planning process within Colorado, and potentially other states.[2480] The Colorado Commission is also concerned that, to the extent interconnection requests are permitted to be made into non-resource

[2476] PJM Initial Comments at 51.

[2477] Indicated PJM TOs Reply Comments at 19.

[2478] North Dakota Commission Initial Comments at 7.

[2479] Interwest Initial Comments at 10.

[2480] Tri-State Initial Comments at 29.

solicitation cluster studies without strong requirements to demonstrate that those requests are for viable generating facilities, the cluster study results may render later resource solicitation study results inaccurate.[2481]

iii. Requests for Alternatives and Regional Flexibility

1315. Public Interest Organizations argue that the Commission should grant extra flexibility on the 135-calendar day study timeline.[2482] Several commenters support the implementation of boundaries or guardrails to ensure that optional resource solicitation studies do not delay the study of other interconnection requests by diverting needed resources away from the general interconnection queue.[2483] Several commenters support the proposal so long as protections are included to prevent undue discrimination and maintain a competitive generation solicitation.[2484]

1316. NARUC asks the Commission to consider going farther than requiring the optional resource solicitation study only for purposes of transparency and cost estimation; it recommends making the results of the studies available for interconnection customers

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[2481] Colorado Commission Reply Comments at 5 n.10.

[2482] Public Interest Organizations Initial Comments at 38.

[2483] Illinois Commission Initial Comments at 11; NESCOE Initial Comments at 18; OPSI Initial Comments at 7-8.

[2484] CREA and NewSun Initial Comments at 89-90; CREA and NewSun Reply Comments at 55; Interwest Initial Comments at 11; Northwest and Intermountain Initial Comments at 16; Pine Gate Initial Comments at 43; Public Interest Organizations Initial Comments at 41; R Street Initial Comments at 15-16.

to pursue and a basis upon which interconnection customers could seek interconnection on an expedited basis.[2485]

1317. Xcel, the Colorado Commission, and EEI argue that the resource solicitation cluster should have its own queue position.[2486] Enel recommends that the optional resource solicitation study be a separate queue cycle with an intermediate queue priority between the transmission provider's annual study clusters.[2487] Several commenters argue that resources selected as part of the resource solicitation process should be given priority in the interconnection queue.[2488] The Colorado Commission suggests that the Commission modify its proposal to prioritize interconnection requests selected to serve native and network load within the RTO/ISO.

1318. The Colorado Commission and Xcel encourage the Commission to determine that any current resource solicitation cluster processes already in place remain just and reasonable or are consistent with/superior to the final rule.[2489] SEIA disagrees, noting that PSCo's existing resource solicitation study procedures were approved by the

[2485] NARUC Initial Comments at 31.

[2486] Colorado Commission Initial Comments at 29; Colorado Commission Reply Comments at 6; EEI Initial Comments at 5-6; Xcel Initial Comments at 11, 14.

[2487] Enel Initial Comments at 72.

[2488] Arizona Commission Initial Comments at 2; Colorado Commission Reply Comments at 2; Public Interest Organizations Initial Comments at 43; Xcel Initial Comments at 46.

[2489] Colorado Commission Reply Comments at 1; Xcel Initial Comments at 11.

Commission in 2004 only so long as PSCo did not "disadvantage or delay other Interconnection Requests not involved in the solicitation."[2490] SEIA argues that the Colorado Commission's current proposal to prioritize interconnection requests selected in the state process conflicts with this 2004 order and the Commission's "longstanding prohibition against queue jumping."[2491]

1319. Multiple commenters request clarification and changes to the NOPR's proposal on resource solicitation in multistate transmission areas,[2492] but NARUC and Xcel suggest that facilitated coordination of resource planning and interconnection as well as discussion across states and LSEs may be the most helpful practice to reduce the burden of differing state portfolio requirements on transmission providers in multi-state areas.[2493]

1320. Several commenters suggest that the proposed optional resource solicitation study should occur outside the tariff process.[2494] NextEra argues that the absence of such a feature from the *pro forma* LGIP is in no way unjust and unreasonable and that, if a transmission provider feels the need to customize its LGIP in this way, the transmission

[2490] SEIA Reply Comments at 20 (citing NOPR, 179 FERC ¶ 61,194 at P 298; *Xcel Energy Operating Cos*., 109 FERC ¶ 61,072, at P 26 (2004)).

[2491] *Id.* at 20-21 (citing *Xcel Energy Operating Cos*., 106 FERC ¶ 61,260, at P 22, *order on reh'g*, 109 FERC ¶ 61,072).

[2492] AEP Initial Comments at 36; CAISO Initial Comments at 31; PacifiCorp Initial Comments at 39; PJM Initial Comments at 51; WAPA Initial Comments at 15; Xcel Initial Comments at 45-46.

[2493] NARUC Initial Comments at 30-31; Xcel Initial Comments at 45.

[2494] NextEra Initial Comments at 35; NRECA Initial Comments at 42.

provider can do so on its own.[2495] NRECA suggests that the Commission require that base cases and support files are available for LSEs so the LSE can run these studies outside of the tariff process.[2496] WAPA and Bonneville argue that resource solicitation studies should occur at the reliability coordinator level and not the transmission provider level.[2497]

1321. Several commenters argue that the Commission should allow transmission providers flexibility in implementing resource solicitations.[2498] NYISO asserts that it has addressed the NOPR's aims by permitting state agencies to act as a developer for purposes of obtaining a generic interconnection request that they can put out for solicitation.[2499]

c. Commission Determination

1322. We decline to adopt the NOPR proposal to modify the *pro forma* LGIP to require transmission providers to allow resource planning entities to initiate an optional resource

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[2495] NextEra Initial Comments at 35.

[2496] NRECA Initial Comments at 42.

[2497] Bonneville Initial Comments at 22; WAPA Initial Comments at 14.

[2498] AECI Initial Comments at 8; Dominion Initial Comments at 39; Interwest Initial Comments at 12; ISO-NE Initial Comments at 38; NESCOE Reply Comments at 15; NRECA Initial Comments at 10; NYISO Initial Comments at 46; PacifiCorp Initial Comments at 39; PJM Initial Comments at 51; Xcel Initial Comments at 14, 45; Xcel Reply Comments at 3.

[2499] NYISO Initial Comments at 47.

solicitation study.[2500] We find that there is insufficient evidence in the record to justify establishing the optional resource solicitation study process proposed in the NOPR as a generic solution across all regions for coordinating state-level resource planning with the interconnection process. As commenters explain, many transmission providers do not have LSEs that conduct a resource solicitation process. We are also concerned that the particular "one size fits all" approach proposed in the NOPR would create uncertainty regarding the cost and timing of interconnecting to the transmission system, because the proposed study would not result in useful network upgrade cost estimates. Finally, we agree with commenters that the proposal as set forth in the NOPR would divert transmission provider resources and potentially lead to delays in the processing of the interconnection queue.

1323. Notwithstanding our decision not to adopt the NOPR's resource solicitation proposal, we agree with commenters who note that, in certain regions, resource solicitation studies have the potential to reduce uncertainty, improve coordination, and make resource planning more efficient and cost effective. We acknowledge comments arguing that a resource solicitation study may be most effective if paired with a structure where the resources within the resource solicitation structure are granted their own queue position, as this provides the relevant resources and soliciting entity with actionable information and avoids the uncertainty and delay that may occur if a study is conducted

[2500] Because we are not adopting this proposal, we do not address comments on specific aspects of the proposal.

only for informational purposes and the associated resources do not have a queue position that corresponds to the study assumptions.[2501] We note that our decision not to adopt the NOPR's proposal in this final rule in no way prejudges any future resource solicitation study proposals that transmission providers may choose to file pursuant to FPA section 205.

C. Reforms to Incorporate Technological Advancements into the Interconnection Process

1. Increasing Flexibility in the Generator Interconnection Process

a. Co-Located Generating Facilities Behind One Point of Interconnection with Shared Interconnection Requests

i. Need for Reform and NOPR Proposal

1324. In the NOPR, the Commission noted that the current *pro forma* LGIP does not address interconnection requests made up of multiple generating facilities seeking to co-locate and to share a single point of interconnection.[2502] The Commission preliminarily found that the lack of such a process limits the interconnection of generating facilities, hindering competition and rendering the Commission's existing *pro forma* LGIP unjust, unreasonable, and unduly discriminatory or preferential.[2503]

[2501] *See* Colorado Commission Initial Comments at 29; Colorado Commission Reply Comments at 6; EEI Initial Comments at 5-6; Xcel Initial Comments at 11, 14.

[2502] NOPR, 179 FERC ¶ 61,194 at P 239.

[2503] *Id.* P 240.

1325. The Commission therefore proposed to revise the *pro forma* LGIP and *pro forma* LGIA to "require transmission providers to allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request."[2504] The Commission explained that this proposed reform would "create a minimum standard that would remove barriers for co-located resources by creating a standardized procedure for these types of configurations to enable them to access the transmission system."[2505]

1326. The Commission proposed to revise the *pro forma* LGIP to: "(1) define 'Co-Located Resources' as 'more than one resource located behind the same point of interconnection'; (2) state that co-located resources can share an interconnection request; (3) modify the definition of site control such that it allows interconnection customers to demonstrate shared land-use for co-located resources."[2506] The Commission also proposed to modify the definition of interconnection facilities to clarify that multiple generating facilities located on the same site may share interconnection facilities.[2507]

1327. The Commission also proposed revisions to the *pro forma* LGIP to "require generating facilities that are co-locating to have technology to address differences in terminal voltage between the co-located generating facilities to ensure that these

[2504] *Id.* P 242.

[2505] *Id.*

[2506] *Id.* P 243.

[2507] *Id.*; proposed *pro forma* LGIP section 1.

generating facilities have the same voltage levels."[2508] The Commission noted that many co-located generating facilities are co-located with electric storage resources,[2509] and proposed to define "electric storage resources" in the *pro forma* LGIP as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.[2510]

ii. Comments

(a) Comments in Support

1328. Commenters overwhelmingly support the Commission's proposal.[2511] Eversource conditionally supports the proposal as a solid step that will improve the interconnection

[2508] NOPR, 179 FERC ¶ 61,194 at P 245.

[2509] *Id.* P 240.

[2510] *Id.*; proposed *pro forma* LGIP section 1.

[2511] AEE Initial Comments at 38; AES Initial Comments at 23; Ameren Initial Comments at 26; APPA-LPPC Initial Comments at 28; CAISO Initial Comments at 32; Clean Energy Associations Initial Comments at 59; Clean Energy Buyers Initial Comments at 4-5; Consumers Energy Company Initial Comments at 8; CREA and NewSun Initial Comments at 90; Environmental Defense Fund Initial Comments at 5; Environmental Defense Fund Reply Comments at 8; ELCON Initial Comments at 10; Enel Initial Comments at 78; Evergreen Action Initial Comments at 3; ISO-NE Initial Comments at 39; MISO Initial Comments at 107; NARUC Initial Comments at 33; National Grid Initial Comments at 39; NextEra Initial Comments at 6; NRECA Initial Comments at 44; NY Commission and NYSERDA Initial Comments at 9; NYISO Initial Comments at 47; NYTOs Initial Comments at 31-32; OSPA Reply Comments at 15; Ohio Commission Initial Comments at 14; Omaha Public Power Initial Comments at 13; Ørsted Initial Comments at 18; Pine Gate Initial Comments at 44-45; Public Interest Organizations Initial Comments at 43; SEIA Initial Comments at 37; SoCal Edison Initial Comments at 19; SPP Initial Comments at 23; State Agencies Initial Comments at 14.

process.[2512] Avangrid is not opposed to the proposal but does not foresee the reform as providing incremental efficiency to transmission providers.[2513]

1329. Evergreen Action avers that co-location is vital to connecting more generation in the short term as transmission providers begin to work through large interconnection queue backlogs,[2514] and Evergreen Action and NRECA state that co-locating two or more resources will take advantage of technologies like battery storage to more efficiently use the transmission system.[2515] AEE and State Agencies argue that, because existing interconnection procedures were designed before battery storage and hybrid resource types came into common usage, these types of technologies are often underserved under existing interconnection procedures despite being well represented in current interconnection queues, making this reform timely.[2516] OSPA urges the Commission to implement this proposal as soon as possible.[2517]

1330. Several commenters argue that the NOPR proposal will likely improve the overall efficiency of interconnection processes, result in more accurate interconnection queue positions, and help to ensure just and reasonable rates.[2518] Environmental Defense Fund

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[2512] Eversource Initial Comments at 32-33.

[2513] Avangrid Initial Comments at 34.

[2514] Evergreen Action Initial Comments at 3.

[2515] *Id.*; NRECA Initial Comments at 44.

[2516] AEE Initial Comments at 38; State Agencies Initial Comments at 14.

[2517] OSPA Reply Comments at 15.

[2518] AEE Initial Comments at 39; AES Initial Comments at 23; NARUC Initial

argues that combinations of generation and storage on a single site will create several benefits, including reducing intermittency, shifting supply to better meet demand, responding to grid events, and enabling provision of ancillary services.[2519]

1331. AEE argues that the greatest value of storage systems is their ability to respond rapidly with a high degree of controllability, and contends that hybrid resources smooth the output of variable resources, allowing for increased land use efficiencies.[2520] Several commenters argue that the proposal will yield interconnection queue efficiency because the shared nature of the co-located resources can be fully accounted for in a single interconnection request: they contend that requiring co-located resources to submit multiple interconnection requests increases cost, timing, and complexity, while forgoing reliability benefits.[2521]

1332. In support of the proposal, AEE argues that several transmission providers already allow co-located generating facilities at the same point of interconnection to submit a single request (e.g., CAISO, ISO-NE, and MISO).[2522] AES contends that the

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Comments at 33; Ohio Commission Initial Comments at 14.

[2519] Environmental Defense Fund Initial Comments at 5.

[2520] AEE Initial Comments at 39.

[2521] *Id.*; AES Initial Comments at 39; Consumers Energy Company Initial Comments at 8; Environmental Defense Fund Initial Comments at 5-6; NARUC Initial Comments at 33; Ohio Commission Initial Comments at 14; Ørsted Initial Comments at 19; Public Interest Organizations Initial Comments at 44; SEIA Initial Comments at 37-38; SoCal Edison Initial Comments at 19.

[2522] AEE Initial Comments at 39-40.

Commission's proposed reforms are necessary to ensure parity across all RTOs/ISOs on this issue, as some RTOs'/ISOs' practices erect unnecessary and unreasonable barriers for generating facilities located behind a single point of interconnection to interconnect.[2523]

1333. Omaha Public Power supports the Commission's proposals to facilitate new technologies, specifically the reforms related to co-located resources, revisions to the modification process, and surplus interconnection capacity.[2524] Omaha Public Power observes, however, that many transmission providers have already made progress in this area and therefore recommends that the Commission allow existing transmission provider processes that are facilitating new technologies to continue.

(b) <u>Comments on Specific Proposal</u>

1334. Avangrid asserts that the Commission's proposal should not change or supersede any regional metering requirements for market participation and contends that co-located resources must have separate meters even if they share a point of interconnection.[2525]

1335. NARUC and MISO support the Commission's proposal that co-located generating facilities must have technology to address differences in terminal voltage between the co-located generating facilities.[2526] MISO states that having to study a single co-located

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[2523] AES Initial Comments at 23.

[2524] Omaha Public Power Initial Comments at 13.

[2525] Avangrid Initial Comments at 34.

[2526] MISO Initial Comments at 107-108; NARUC Initial Comments at 33.

generating facility with two points of interconnection at different voltages would be infeasible, and that co-located generating facilities should be required to inject at a single point of interconnection, at a single voltage.[2527] SPP states that it is unclear what the Commission intended in the NOPR by proposing to require that generating facilities "address differences in terminal voltage between the co-located generating facilities to ensure that these generating facilities have the same voltage levels."[2528] SPP contends that it would be simpler to require that such generating facilities connect at the same point of interconnection and leave the details as to how to do that to the interconnection customer. Ameren argues that, so long as modeling is available to the transmission provider for the types of resources that are behind the point of interconnection, co-located resources with differences in terminal voltage should not be an issue when performing the interconnection studies.[2529]

1336. Ørsted supports the Commission's proposed changes to the definition of "interconnection facilities."[2530] Enel states that the proposed insertion of the phrase "by interconnection customer" in the third sentence of the *pro forma* LGIA/LGIP definition of "interconnection facilities" should be changed to the phrase "by interconnection

[2527] MISO Initial Comments at 107-108.

[2528] SPP Initial Comments at 23 (citing NOPR, 179 FERC ¶ 61,194 at P 245).

[2529] Ameren Initial Comments at 26.

[2530] Ørsted Initial Comments at 18.

customer(s)."[2531] Enel further states that the proposed new fourth sentence to the definition of "interconnection facilities" explains that multiple interconnection customers may use a single set of interconnection facilities, and thus "sole use facilities" may have multiple interconnection customer beneficiaries.

1337. Southern states that, under the NOPR proposal, co-located resources can include different owners of different generating facilities.[2532] Pine Gate and Southern note that the proposal to allow interconnection customers to demonstrate shared land-use may require interconnection customers to provide transmission providers more detailed site maps to demonstrate valid site control for each generating facility.[2533] Southern states that this is appropriate because the transmission provider should not be responsible for monitoring the legal relationship between the co-owners.[2534] Southern states that co-located resources must either be owned by the same owner, or the different owners of the generating facilities must enter into an agreement that addresses off-take rights and ownership, and they must submit one interconnection request for the entire generating facility. Tri-State suggests clarifying that a separate agreement is not necessary when both co-located resources belong to the same interconnection customer.[2535]

[2531] Enel Initial Comments at 81-82.

[2532] Southern Initial Comments at 35.

[2533] *Id.* at 36; Pine Gate Initial Comments at 46.

[2534] Southern Initial Comments at 36.

[2535] Tri-State Initial Comments at 25.

1338. Clean Energy Associations support allowing multiple generating facilities that share a single point of interconnection to submit a joint interconnection request as a hybrid or co-located resource. Clean Energy Associations argue that interconnection customers with proposed generating facilities where the electric storage resource and generating facility are co-located, and have two "resource IDs," should be allowed to choose to have each component studied separately.[2536] Clean Energy Associations also submit that the generating equipment for the generating facilities should not be required to be located on a shared site. Clean Energy Associations further assert that such flexibility would allow, for example, a solar facility to obtain a faster ERIS study while the co-located storage could get a more detailed study for NRIS.

1339. Southern contends that co-located resources that intend to be qualifying facilities should be required to comply with PURPA requirements.[2537]

(c) <u>Requests for Clarification and Flexibility</u>

1340. Pine Gate agrees that co-located generating facilities must have technology to address differences in terminal voltage between the co-located generating facilities, arguing that such technology is likely necessary in instances where a co-located resource is being studied under a single interconnection request for a net injection at the point of interconnection.[2538] However, Pine Gate requests that the Commission clarify that such

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[2536] Clean Energy Associations Initial Comments at 59-61.

[2537] Southern Initial Comments at 36.

[2538] Pine Gate Initial Comments at 46.

technology is not necessary in instances in which the interconnection customer elects to submit a co-located resource using two separate interconnection requests.

1341. SPP notes that in the NOPR, the Commission proposed to define "co-located resources" as "more than one resource located behind the same point of interconnection," whereas the proposed definition in the *pro forma* LGIP reads, "Co-Located Resource shall mean multiple Generating Facilities located on the same site."[2539] SPP states that two generating facilities can be located on the same site without connecting behind the same point of interconnection. SPP asks the Commission to clarify in the final rule which definition of co-located resource is required. SPP states that it supports a definition that explicitly states that the generating facilities must connect at the same point of interconnection.

1342. MISO and Southern request that the Commission clarify that co-located resources must be required to share an interconnection request.[2540] According to MISO, its tariff and Order No. 807[2541] allow for different interconnection requests to share a generator tie line and thus share the same point of interconnection. MISO argues that failing to amend the definition of co-located resource would conflate the two scenarios under the same definition, such that two separate noncontiguous generating facilities that share a

[2539] SPP Initial Comments at 23.

[2540] MISO Initial Comments at 107; Southern Initial Comments at 36.

[2541] *Open Access & Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 80 FR 17654 (Apr. 1, 2015), 150 FERC ¶ 61,211, *order on reh'g*, Order No. 807-A, 153 FERC ¶ 61,047 (2015).

generator tie line would share the same point of interconnection, thus also falling under the definition of co-located resources without the intent to do so.[2542] Southern argues that the Commission should clarify that the interconnection tie line connecting the co-located resource to the transmission system is a radial facility, not a network facility.[2543]

1343. National Grid asks that the Commission clarify what is included in the definition of "co-located resources."[2544] National Grid understands that the term can apply to hybrid technologies owned by a single interconnection customer interconnecting to a single point of interconnection, such as a solar generating facility coupled with a storage facility. National Grid suggests that, to the extent the term also is intended to apply to multiple interconnection customers with separate generating facilities interconnecting to a single point of interconnection, that the proposal might create complexities not discussed in the NOPR but may merit consideration.

1344. SEIA requests clarification on the terminology used in the proposal.[2545] SEIA states that in January 2021, in its order directing reports on information related to hybrid resources, the Commission used two distinct terms to identify hybrid resource market participation.[2546] SEIA states that "co-located hybrid resources" are defined as two

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[2542] MISO Initial Comments at 107.

[2543] Southern Initial Comments at 37.

[2544] National Grid Initial Comments at 39-40.

[2545] SEIA Initial Comments at 38.

[2546] *Id.* (citing *Hybrid Res.*, 174 FERC ¶ 61,034, at P 4 (2021)).

separate resources sharing a single point of interconnection that are modeled and dispatched separately. SEIA states that “integrated hybrid resources” are defined as sets of resources that share a single point of interconnection and are modeled and dispatched as a single resource. Tri-State similarly states that the “electric storage resource” definition does not account for resources designed to be charged apart from the transmission system, such as solar or wind generating facilities that may charge an electric storage resource.[2547] SEIA requests that the Commission adopt the terms co-located and integrated hybrid resources in the final rule and clarify that interconnection customers retain the choice of how to structure their interconnection requests to best suit their needs and the needs of their customers.[2548]

1345. Some commenters ask that the Commission provide regional flexibility as to the types of co-located resources permitted in each RTO/ISO and existing processes that may already accomplish the goals of the proposed reforms.[2549] ISO-NE, NYISO, and MISO state that they are already in compliance with the proposed reform.[2550]

[2547] Tri-State Initial Comments at 25.

[2548] SEIA Initial Comments at 38.

[2549] ISO-NE Initial Comments at 39; NY Commission and NYSERDA Initial Comments at 9; NYTOs Initial Comments at 31-32.

[2550] ISO-NE Initial Comments at 39; MISO Initial Comments at 107; NYISO Initial Comments at 47.

iii. Commission Determination

1346. We adopt, with modification, the NOPR proposal to revise *pro forma* LGIP section 3.1.2 to require transmission providers to allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request. We decline to adopt the proposed definitions of "co-located resource" and "electric storage resource," and we decline to adopt the proposed modifications to the definitions of interconnection facilities, and transmission provider's interconnection facilities in *pro forma* LGIP section 1 and *pro forma* LGIA article 1.[2551] We find that including the definition of co-located resource in the *pro forma* LGIP and *pro forma* LGIA is not necessary to effectuate the process reforms detailed in the NOPR, and thus decline to adopt it here.[2552] Given that Order No. 845 revised the definition of generating facility to include electric storage resources,[2553] we also find it unnecessary to define the term electric storage resource in the *pro forma* LGIP and LGIA. We note that declining to adopt the definition of electric storage resource moots Tri-State's concern

[2551] NOPR, 179 FERC ¶ 61,194 at P 243; proposed *pro forma* LGIA section 1.

[2552] Co-located generating facilities are more than one generating facility that are located on the same site and that are connected at the same point of interconnection that are operated and dispatched as separate generating facilities.

[2553] *See* Order No. 845, 163 FERC ¶ 61,043, at P 275 (modifying the definition of "Generating Facility" in the *pro forma* LGIP and *pro forma* LGIA to include "and/or storage for later injection").

that the proposed definition failed to account for electric storage resources that may be charged apart from the transmission system.[2554]

1347. We also decline to adopt the NOPR proposal to modify the definitions of interconnection facilities and transmission provider's interconnection facilities to specify that interconnection facilities may be shared among interconnection customers. We find that such specification in the *pro forma* LGIP and *pro forma* LGIA is not needed because Commission policy does not prohibit interconnection customers from sharing interconnection facilities.[2555] We expect that there may be benefits from interconnection customers being able to share transmission provider's interconnection facilities and interconnection customer's interconnection facilities, particularly in light of the Commission's transition in this final rule to a cluster study approach. Under a cluster study approach, in which multiple interconnection requests are evaluated in a combined study, efficiencies may be gained (in cost and time to construct) by allowing interconnection customers to share use of, and payment for, interconnection facilities. We note that such efficiencies from allowing the interconnection facilities to be used by more than one interconnection customer do not exist under the Commission's existing *pro forma* LGIP serial interconnection study process because the serial study process does not consider the interconnection facilities that would be necessary to accommodate

[2554] Tri-State Initial Comments at 25.

[2555] *See, e.g.*, Order No. 807, 150 FERC ¶ 61,211, at P 3 (discussing the ability of interconnection customer's interconnection facilities owners to make excess capacity available to third parties).

the interconnection of *more than one interconnection customer*. In response to Ørsted and Enel's comments expressing support for the revisions to the definitions of interconnection facilities and transmission provider's interconnection facilities,[2556] we state in this final rule that the interconnection facilities also may be used by more than one interconnection customer.

1348. We also decline to adopt the NOPR proposal to revise the *pro forma* LGIP to require generating facilities that are co-locating to have technology to address differences in terminal voltage between the co-located generating facilities to ensure that these generating facilities have the same voltage levels.[2557] We find that the preexisting language in *pro forma* LGIP section 3.1 (section 3.1.2 as revised by this final rule) is clear that "[a]n Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests." This preexisting provision makes clear that a set of co-located generating facilities must be at a single terminal voltage in order to be treated as a single interconnection request. The additional requirement proposed in the NOPR is therefore unnecessary to adopt in the final rule. We note that declining to adopt the NOPR proposal with respect to this issue alleviates SPP's concern with the NOPR proposal.[2558] In response to Pine Gate, we reiterate that preexisting *pro forma* LGIP section 3.1 (section 3.1.2 as revised by this final rule) would

[2556] Ørsted Initial Comments at 18; Enel Initial Comments at 81-82.

[2557] *See* NOPR, 179 FERC ¶ 61,194 at P 245.

[2558] *See* SPP Initial Comments at 23.

require co-located generating facilities with different terminal voltage levels to submit separate interconnection requests.[2559]

1349. As the Commission stated in the NOPR, recent studies demonstrate that large numbers of generating facilities currently in interconnection queues are seeking to co-locate on a shared site behind one point of interconnection and share an interconnection request, while operating separately, and that the *pro forma* LGIP currently lacks provisions that explicitly allow them to do so.[2560] We agree with commenters that this type of generating facility configuration, in spite of being prevalent in current interconnection queues, faces barriers to interconnection under existing interconnection procedures,[2561] and that this reform will effectively remove such barriers. We find that requiring transmission providers to allow interconnection customers to submit a single interconnection request that represents multiple generating facilities that are located behind a single point of interconnection is required to ensure just and reasonable rates. By doing so, this reform will improve efficiency for transmission providers in the study process by reducing the number of interconnection requests in the interconnection queue and will reduce costs for interconnection customers because they will only submit a single set of deposits to enter the interconnection queue.

[2559] *See* Pine Gate Initial Comments at 46.

[2560] NOPR, 179 FERC ¶ 61,194 at P 238.

[2561] AEE Initial Comments at 38; State Agencies Initial Comments at 14.

1350. We also believe that this reform will improve interconnection queue efficiency without imposing an adverse impact on the efficacy of interconnection study results or other interconnection customers. Because of the significant growth of generating facilities seeking to interconnect jointly at a single point of interconnection,[2562] we find that allowing co-located generating facilities to submit one interconnection request will lessen the delays experienced in many interconnection queues. We agree with commenters that transmission providers requiring co-located generating facilities to submit separate interconnection requests increases the cost and complexity of the interconnection process and creates undue delay to the interconnection process.[2563] Allowing co-located generating facilities to share interconnection requests will ensure the interconnection queue moves along expediently, providing clarity, cost certainty, and increased transparency throughout the study process.

1351. Some commenters suggest that co-located generating facilities should always be required to share an interconnection request.[2564] Others request that interconnection customers retain the choice whether to share an interconnection request.[2565] We clarify

[2562] Currently, 42% (285 GW) of solar and 8% (17 GW) of wind projects in the queue are proposed as hybrid resources that would include electric storage. Queued Up 2023 at 18.

[2563] AEE Initial Comments at 39; Environmental Defense Fund Initial Comments at 5-6.

[2564] MISO Initial Comments at 107; Southern Initial Comments at 36.

[2565] Clean Energy Associations Initial Comments at 59-61 (arguing against such a requirement to enable co-located generating facilities to seek ERIS versus NRIS); SEIA

that interconnection customers have the choice to structure their interconnection requests according to their preference. We are not *requiring* interconnection customers to share a single interconnection request for multiple generating facilities located on the same site.

1352. However, we further clarify in response to Clean Energy Associations[2566] that interconnection customers may submit separate interconnection requests to have each device studied separately. We find that this clarification also addresses MISO's concern about any potential conflict with Order No. 807.[2567] Additionally, we clarify that, where an interconnection customer chooses to submit a single interconnection request for multiple generating facilities, the generating facilities must be located on the same site in order to reduce complexity for the transmission provider.

1353. In response to Southern's request that the Commission clarify that the interconnection tie line connecting the co-located resource to the transmission system is a radial facility, not a network facility, we clarify that, as explained in Order No. 807, the Commission now refers to tie lines as the interconnection customer's interconnection facilities.[2568] As the Commission stated in Order No. 807, the interconnection customer's

Initial Comments at 38.

[2566] Clean Energy Association Initial Comments at 59-61 (requesting that generating equipment not be required to be on the same site).

[2567] MISO Initial Comments at 107-108.

[2568] The Commission stated that "[t]he jurisdictional interconnection facilities for which this Final Rule grants a waiver have sometimes in the past been referred to informally as 'generator tie lines,' but, in the Notice of Proposed Rulemaking, the Commission used the term [Interconnection Customer's Interconnection Facilities] as defined in the *pro forma* documents issued with Order No. 2003." Order No. 807,

interconnection facilities "are sole-use, limited and discrete, radial in nature, and not part of an integrated transmission network."[2569] Radial facilities located between the generating facility and point of interconnection are considered interconnection facilities under the *pro forma* LGIP and *pro forma* LGIA.[2570]

1354. In response to Omaha Public Power's suggestion that the Commission allow existing transmission provider processes that are facilitating new technologies to continue unimpeded, we clarify that, consistent with Section IV of this final rule, to the extent transmission providers believe that they already comply with the adopted *pro forma* LGIP provisions, they may demonstrate this in their compliance filings.

1355. In response to concerns about multiple interconnection customers using the same interconnection request,[2571] we clarify that co-located generating facilities can be owned by a single interconnection customer with multiple generating facilities sharing a site, or by multiple interconnection customers that have a contract or other agreement that allows

150 FERC ¶ 61,211, at n.1 (citing Order No. 2003, 104 FERC ¶ 61,103).

[2569] Order No. 807, 150 FERC ¶ 61,211 at P 114.

[2570] Under the *pro forma* LGIP, "Interconnection Facilities shall mean Transmission Provider's Interconnection Facilities and Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades." *See pro forma* LGIP section 1 and *pro forma* LGIA article 1.

[2571] National Grid Initial Comments at 39-40; Southern Initial Comments at 35-36.

for shared land use.[2572] In response to Tri-State,[2573] we clarify that no such agreement is necessary when the generating facilities in question belong to the same interconnection customer. In response to Southern,[2574] we clarify that generating facilities that co-locate still must adhere to all other applicable laws and regulations, including PURPA.

1356. We find that comments regarding the following issues are outside the scope of this proceeding because they pertain to market issues and other rules that were not addressed in the NOPR: (1) permitting an interconnection customer to specify the co-located generating facility's maximum injection level to the point of interconnection;[2575] and (2) metering requirements for co-located generating facilities.[2576]

1357. We decline SEIA's request that the Commission adopt a more expansive definition of "co-located resources," including how the resources are modeled and dispatched. Modeling assumptions for electric storage resources and co-located or hybrid generating facilities containing electric storage resources are addressed elsewhere in this final rule.[2577]

[2572] The revised definition of site control in the *pro forma* LGIP adopted in this final rule requires that site control be "demonstrated by a contract or other agreement that allows for shared land use for all Generating Facilities that are co-located and meet the provisions of the Site Control definition." *Pro forma* LGIP section 3.4.2.

[2573] Tri-State Initial Comments at 25.

[2574] Southern Initial Comments at 36.

[2575] Pine Gate Initial Comments at 45.

[2576] Avangrid Initial Comments at 34.

[2577] *See infra* Section III.C.1.d.

b. Revisions to the Modification Process to Require Consideration of Generating Facility Additions

i. Need for Reform and NOPR Proposal

1358. In the NOPR, the Commission expressed concern that, because certain requests to add a generating facility to an existing interconnection request are often deemed material without an evaluation, even if the injection amount remains the same, the material modification process may result in unjust, unreasonable, and unduly discriminatory or preferential outcomes.[2578] The Commission pointed out that, as explained in Order No. 2003, it is inadequate and inefficient to solve interconnection issues on a case-by-case basis.[2579] The Commission explained that, in the case of processing modification requests, without a standard set of procedures, transmission providers have adopted varying strategies for processing requests to add electric storage or other generating facilities that do not change the requested interconnection service limit to existing interconnection requests. The Commission preliminarily found that this lack of uniformity leads to disparate outcomes across the country and leaves open the potential for undue discrimination.

1359. The Commission explained that the modification provisions in the *pro forma* LGIP do not specify whether an interconnection customer can modify its interconnection request to add another generating facility at the same point of interconnection without

[2578] NOPR, 179 FERC ¶ 61,194 at P 252.

[2579] *Id.* (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 9-10).

increasing the requested interconnection service level.[2580] The Commission stated that many transmission providers treat such a request automatically as a material modification, such that the interconnection customer that wishes to make this type of change faces a loss of interconnection queue position regardless of the actual effect the addition of a generating facility to an interconnection request may have on the system. The Commission explained that this process is a significant barrier to interconnection customers that wish to make this type of change and preliminarily found that such a barrier hinders access to the transmission system and may render existing interconnection processes unjust, unreasonable, and unduly discriminatory or preferential.[2581]

1360. In the NOPR, the Commission proposed to revise the *pro forma* LGIP to require transmission providers to evaluate the proposed addition of a generating facility to an interconnection request as long as the interconnection customer does not request a change to the originally requested interconnection service level.[2582] Under this proposed requirement, the transmission provider could not automatically consider such a request to be a material modification. Specifically, the Commission proposed to require that: "(1) transmission providers evaluate the proposed addition of a generating facility to an interconnection request within 60 calendar days of receiving the request for modification if such addition does not change the requested interconnection service level; (2) the

[2580] *Id.* P 253.

[2581] *Id.* P 254.

[2582] *Id.* P 255.

change cannot be considered an automatic material modification and an evaluation (including studying the configuration and necessary modeling) must occur prior to determining whether the proposed change constitutes a material modification of the interconnection request; and (3) if the proposed addition does not have a material impact on the cost or timing of any interconnection request that is lower or equally queued, and does not cause any other reliability concerns, the addition will not be considered a material modification."[2583] The Commission noted that the reliability concerns could include, for example, a material impact on the transmission system with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response.

1361. The Commission sought comment on: "(1) whether the addition of a generating facility that does not alter an interconnection customer's interconnection service limit could nonetheless require a full interconnection service study; (2) how transmission providers should perform studies required to confirm that there is no adverse impact because of the addition of a generating facility to an interconnection request, such as confirmation that the electrical characteristics of the interconnection customer remain the same; (3) whether and how interconnection customers in a later cluster, or interconnection customers that are in the same cluster, could be adversely impacted by such changes; (4) whether the addition of electric storage when in charging mode (in terms of resistance, inductance, and capacitance) may change the electrical characteristics

[2583] *Id.* P 255.

of an interconnection request, and whether those changes may affect the reliable operation of the generating facility related to that interconnection request; and (5) whether further specification is needed for the assessment of the electrical characteristics due to the addition of a complex load."[2584]

ii. Comments

(a) Comments in Support

1362. A diverse group of commenters indicate general support for the NOPR proposal.[2585] NARUC agrees that the proposed reform will promote consistency for interconnection customers throughout the country, in addition to promoting reliability, economic, and administrative efficiency as the generation fleet continues to evolve.[2586] NARUC explains that the loss of interconnection queue position as a result of adding a

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[2584] *Id.* PP 256-257.

[2585] AEE Initial Comments at 40-41; AEE Reply Comments at 39-41; AES Initial Comments at 23; Ameren Initial Comments at 27; APS Initial Comments at 20; Avangrid Initial Comments at 34-35; CAISO Initial Comments at 32; Clean Energy Associations Initial Comments at 59-61; CREA and NewSun Initial Comments at 90-91; Cypress Creek Initial Comments at 18-19; Environmental Defense Fund Initial Comments at 6; Environmental Defense Fund Reply Comments at 8-9; ENGIE Initial Comments at 10-11; EPSA Initial Comments at 13; Equinor Wind Reply Comments at 5-6; Illinois Commission Initial Comments at 13-14; NARUC Initial Comments at 33-35; National Grid Initial Comments at 40 (noting qualifications); NRECA Initial Comments at 44; NY Commission and NYSERDA Initial Comments at 9; NYTOs Initial Comments at 31; Omaha Public Power Initial Comments at 13; Ørsted Initial Comments at 8; Ørsted Reply Comments at 7; PacifiCorp Initial Comments at 39-40; Pine Gate Initial Comments at 44, 47-49; OPSI Initial Comments at 9-10; Public Interest Organizations Initial Comments at 45-47; SEIA Initial Comments at 38-39; Shell Initial Comments, app. A at ii; SPP Initial Comments at 24; UMPA Initial Comments at 7-9.

[2586] NARUC Initial Comments at 33-35.

generating facility that does not increase the requested service level or cause reliability issues, but rather could improve the performance and capability of a generating facility to manage reliability or lower the cost of energy to customers, is an inefficient and discriminatory outcome the Commission should seek to permanently remedy through this proceeding. AEE and Public Interest Organizations assert that a restudy would be automatically required for adding a generating facility such as storage, and that if there were not a restudy related to the addition of storage, they could provide numerous benefits, including firming up variable renewable generation, avoided curtailment, congestion relief, and, in the case of grid-forming inverters and batteries, fast frequency response and other grid flexibility services.[2587] AEE contends that the loss of the benefits, primarily from adding storage, will harm reliability and result in unjust and unreasonable rates.[2588] SEIA contends that adding an additional generating facility (such as storage) that does not increase the interconnection service level also should not increase the costs to later interconnection requests because it generally would not require additional network upgrades and should not delay lower-queued interconnection requests.[2589]

[2587] AEE Initial Comments at 40-41; Public Interest Organizations Initial Comments at 45.

[2588] AEE Initial Comments at 40-41.

[2589] SEIA Initial Comments at 38-39; *see also* ENGIE Initial Comments at 10-11.

1363. Clean Energy Associations and Shell add that a generating facility's addition of energy storage capability without increasing the power capability upon which its interconnection service level is based (e.g., increasing a two-hour battery to a four-hour battery) should not automatically be considered a material modification.[2590] Clean Energy Associations also argue that the removal of a generating facility from a hybrid or co-located resource interconnection request should not automatically be considered a material modification if interconnection service levels do not change.[2591] Clean Energy Associations also request that the material modification rules allow for an increase in the underlying capability of the generating facility, rather than simply an addition of a new resource.

1364. Ameren believes that when considering the addition of a generating facility to an interconnection request, it is important to protect reliability while avoiding unjustly limiting interconnection customer changes by automatically deeming them material modifications.[2592] National Grid supports the proposal but asks the Commission to acknowledge that there may be instances when a determination that the requested generating facility addition is a material modification is necessary, such as if: (1) changes in load characteristics of the generating facility or in electrical characteristics of

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[2590] Clean Energy Associations Initial Comments at 59-61; Shell Initial Comments, app. A at ii.

[2591] Clean Energy Associations Initial Comments at 59-61.

[2592] Ameren Initial Comments at 27.

a resource; or (2) impacts to other interconnection customers in the interconnection queue.[2593] SPP also generally supports the proposal but similarly notes there may be instances when a request that does not alter the interconnection service amount, it could require a full interconnection study and result in additional network upgrades (e.g., a request to change a generating facility from one type to another where changes to electric characteristics impact stability, fault current, or both).[2594]

1365. AES supports the proposal because it adds flexibility to the interconnection process, including the efficient addition of generating facilities such as electric storage resources to previously submitted interconnection requests.[2595] UMPA supports the flexibility of a generating facility's design if a more commercially viable option could be pursued without changing the level of interconnection service or causing reliability concerns, in particular when a prospective interconnection customer intends to acquire a preexisting interconnection queue position in accordance with *pro forma* LGIP section 4.3.[2596]

1366. AEE suggests that the flexibility to adopt "modest modifications" is important due to the current length of the interconnection process, technology changes, price declines,

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[2593] National Grid Initial Comments at 40.

[2594] SPP Initial Comments at 24.

[2595] AES Initial Comments at 23.

[2596] UMPA Initial Comments at 8.

and other factors such as supply chain challenges.[2597] AEE recognizes that some modifications may be material and will require restudy but suggests that disallowing modest changes like adding energy storage that may be beneficial, will harm reliability, and could increase consumer costs by limiting the ability to respond to changing opportunities and needs. NRECA supports the reform if it results in better use of the transmission system but argues that flexibility should not come at the expense of the NOPR's overall goal of reducing speculative interconnection requests, withdrawals, and restudies.[2598]

1367. Some commenters point out that certain RTOs/ISOs use similar approaches to those proposed.[2599] NARUC highlights that certain planning regions have demonstrated that they can reliably accommodate generating facility additions that do not increase requested services levels without treating the modification as a material change.[2600] NARUC underscores CAISO's flexible process that allows interconnection customers to modify the interconnection request and treats fewer resource additions as a material modification, which results in more consistent and predictable interconnection queue outcomes and ultimately more optimized investments.

[2597] AEE Initial Comments at 40-41.

[2598] NRECA Initial Comments at 44.

[2599] CAISO Initial Comments at 32; NY Commission and NYSERDA Initial Comments at 9; NYISO Initial Comments at 48-49; SPP Initial Comments at 24.

[2600] NARUC Initial Comments at 33-35.

(b) Comments in Opposition

1368. A number of commenters oppose the proposal.[2601] ISO-NE and Idaho Power argue that the Commission should require that interconnection requests be fully conceived by the time a cluster request window is closed and modifications be proposed in a subsequent cluster so it does not delay the cluster.[2602] ISO-NE contends that the flexibility in the proposal is contrary to the NOPR's goal of improving study completion timelines and readiness requirements because adding a generating facility to an interconnection request could introduce major changes to study scope, upgrade results, and delay rather than increase study time speed.[2603]

1369. MISO opposes the proposal because it believes that the proposal will increase speculative interconnection requests, contrary to the stated intention of NOPR, and that the balance is disrupted between flexibility to make changes and promoting fairness and certainty to other interconnection customers.[2604] PJM, MISO, and Indicated PJM TOs argue that the proposal will cause delays and divert resources that would have been used

[2601] Ameren Initial Comments at 27; Cypress Creek Initial Comments at 18-19; Eversource Initial Comments at 33-34; Idaho Power Initial Comments at 13; Indicated PJM TOs Initial Comments at 52-54; Indicated PJM TOs Reply Comments at 36-38, 52-54; ISO-NE Initial Comments at 39-40; MISO Initial Comments at 10; NERC Initial Comments at 19-20; PacifiCorp Initial Comments at 39-40; PJM Initial Comments at 18-19, 51-53; Southern Initial Comments at 37-38; SPP Initial Comments at 24.

[2602] ISO-NE Initial Comments at 39-40; Idaho Power Initial Comments at 13.

[2603] ISO-NE Initial Comments at 39-40.

[2604] MISO Initial Comments at 108-12 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 177 FERC ¶ 61,234, at P 12 (2021)); *see also* MISO Reply Comments at 9.

toward processing the interconnection queue,[2605] and MISO states the proposal may enable an end-run around its site control deadlines by giving interconnection customers more time to obtain site control.[2606]

1370. MISO states that, each time an interconnection customer requests a fuel change (including the addition of storage), under the proposal, MISO would have to determine if a material modification exists within 60 days by doing the following: (1) stop processing the interconnection queue, create an alternative model, and then run two system impact studies based on the different models (original and alternate) to determine if there were any changes between the two studies; (2) rebuild the models of any lower-queued cycles and run alternate system impact studies to determine if that would create any impacts for those interconnection requests, which MISO would not be able to complete within 60 days; and (3) correct the data that had been sent to an affected system operator, noting it is unclear if the affected system operator would be able to inform MISO if the change in data created a material modification.[2607] MISO notes that it uses fuel-based dispatch in its interconnection modeling, which exacerbates the above problems because it models individual fuel types in different ways, and includes electric storage in its definition of a

[2605] Indicated PJM TOs Reply Comments at 38; Indicated PJM TOs Initial Comments at 52-54; MISO Initial Comments at 108-12; PJM Initial Comments at 6.

[2606] MISO Initial Comments at 108-12.

[2607] *Id.*

different fuel type, so the addition of electric storage would result in a different type of modeling.[2608]

1371. PJM argues that interconnection customers should only be able to modify their interconnection requests in certain circumstances, pointing to its proposal to allow interconnection customers to make changes that meet pre-defined conditions at three decision points, with the changes at each decision point restudied together.[2609] PJM claims that even if the maximum generating facility output or capacity interconnection rights do not increase, adding a generating facility to an interconnection request can affect other interconnection customers. PJM and Avangrid assert that substituting battery storage facilities for a portion of a solar generating facility or other generating facility without changing the generating facility's maximum output or capacity interconnection rights would likely be a material modification because it would require a light load test or other testing that was not performed for the original solar generating facility interconnection request.[2610] Ameren also states that such interconnection request changes can present challenges (e.g., when an interconnection customer's chosen technology changes due to the passage of time) and can raise reliability issues if not properly addressed, and therefore it is necessary to evaluate or conduct a restudy to make sure that

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[2608] *Id.* at 110.

[2609] PJM Initial Comments at 51-52 (citing PJM Interconnection, L.L.C., Filing, Docket No. ER22-2110-000 (filed June 14, 2022)); *see also* SEIA Reply Comments at 23 (supporting PJM's suggestion).

[2610] PJM Initial Comments at 51-52; Avangrid Initial Comments at 34-35.

the studies reflect the technologies actually being interconnected.[2611] PacifiCorp similarly argues that requests to incorporate grid-charging battery storage technology should be processed separately because grid-charging capabilities can alter the electrical characteristics of an interconnection request.[2612] NV Energy states that in these situations more detailed studies may be required in areas of the transmission system where the fault duty is already high.[2613]

1372. Southern argues that the proposal should not accept modifications to interconnection requests without review because these requests could affect other interconnection customers in the same cluster as well as lower-queued clusters, adding that it may be a material modification that impacts the cost or timing of other interconnection requests.[2614]

1373. MISO asserts that it is unclear if the NOPR proposal will require the interconnection customer to submit evidence of site control before making the modification request or after the request is granted.[2615] Idaho Power notes that site control requirements (primarily acreage) are based on the technology type used in the interconnection request and would require modification if the technology is changed.[2616]

[2611] Ameren Initial Comments at 27.

[2612] PacifiCorp Initial Comments at 39-40.

[2613] NV Energy Initial Comments at 18.

[2614] Southern Initial Comments at 37-38.

[2615] MISO Initial Comments at 108-12.

[2616] Idaho Power Initial Comments at 13.

Idaho Power therefore argues that changing fuel type enables speculative interconnection requests that can affect other interconnection customers both in later clusters and in the same cluster.

1374. Indicated PJM TOs also contend that not treating fuel type changes as material modifications would provide gaming opportunities, e.g., an interconnection customer could bypass the site control demonstration required at the outset of the study process by entering the interconnection queue with a proposed storage project with a small site footprint and later, without changing the size of the interconnection, adding a solar farm with a much larger site footprint.[2617] MISO also notes that the NOPR proposal is contrary to a recent Commission-approved MISO tariff revision regarding changing fuel types while it the interconnection queue, that went through a lengthy stakeholder process.[2618] MISO states that it uses fuel-based dispatch assumptions for interconnection modeling and argues that there is not a simple process to determine if changing fuel during the middle of the interconnection process could cause harm to lower- or equally queued interconnection requests without running a new study based on the updated model. MISO explains that it studies storage generating facilities differently than renewable generating facilities, and this affects the interconnection modeling.[2619]

[2617] Indicated PJM TOs Initial Comments at 52-54; Indicated PJM TOs Reply Comments at 38.

[2618] MISO Initial Comments at 112-13.

[2619] *Id.* at 108-12.

1375. Indicated PJM TOs argue that determining the "materiality" of a particular type of generating facility modification needs to take into account the cumulative impact on the cluster studies of all similar requests.[2620] Indicated PJM TOs explain that, even if a type of modification sought by a single interconnection customer may have modest system impacts and thus not be "material" in a particular case, the cumulative impact of multiple similar requests in the same area could be much larger.

1376. Indicated PJM TOs contend, however, that certain modifications made behind the point of interconnection have reliability impacts requiring restudy and thus amount to material modifications (e.g., changing fuel type by adding storage to a generating facility).[2621] Indicated PJM TOs contend that such changes will likely affect short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response.[2622] Indicated PJM TOs also ask that the Commission recognize that different fuel types among resources have very different seasonal characteristics and dynamic response, arguing that the overall reliability of the transmission system could suffer if certain types of changes are incorrectly identified as non-material.[2623] However, Shell

[2620] Indicated PJM TOs Reply Comments at 38.

[2621] *Id.* at 37-38.

[2622] *Id.* at 38 (citing PJM Interconnection, L.L.C., Answer, Docket No. ER19-1958-002, at 5 n.16 (filed Apr. 29, 2020)); Indicated PJM TOs Initial Comments at 52-54.

[2623] Indicated PJM TOs Initial Comments at 52-54; Indicated PJM TOs Reply Comments at 38.

contends that studies of the addition of a generating facility to an interconnection request should be limited to determining increased costs and/or study or construction delays of equal or lower-queued interconnection requests.[2624]

1377. Indicated PJM TOs ask that, at a minimum, the Commission allow transmission providers to determine the scope of "material modifications" based on their practical experience on their own systems and apply that knowledge as to the types of changes that typically affect other customers and that trigger the need for restudies.[2625] Tri-State asserts that, when the performance of a new proposed generating facility differs from the existing/incumbent generating facility, transient stability analysis would be required but steady state analysis (thermal/voltage) would not be required.[2626]

1378. NERC argues that transmission providers should study the potential impacts of any material change to the generating facility, such as the addition of storage, even when the interconnection service level does not change, because material modifications to the generating facility could alter stability and the interaction of a resource with the transmission system (e.g., adding inverters, which can increase short circuit current, and charging batteries from the transmission system, which can impact system power flow).[2627]

[2624] Shell Initial Comments, app. A at ii.

[2625] Indicated PJM TOs Reply Comments at 39.

[2626] Tri-State Initial Comments at 22.

[2627] NERC Initial Comments at 19-20.

1379. Eversource argues that transmission providers cannot be expected to meet strict deadlines in an adversarial environment while interconnection customers may compound these issues by suggesting significant (even if not "material" by the definition of the revised *pro forma* LGIP) changes to their generating facilities in the middle of the interconnection process.[2628]

(c) Comments on Specific Matters

(1) Comments Seeking Materiality Guidelines

1380. Public Interest Organizations assert that the lack of a standardized definition in the *pro forma* LGIP of what constitutes a material modification, such as the addition of storage, leads to a lack of uniformity among transmission providers and disparate outcomes that could result in undue discrimination.[2629] Similarly, Environmental Defense Fund asks the Commission to clarify how much flexibility transmission providers will be permitted in determining whether adding co-located generating facilities changes the service level and becomes a material modification, and it suggests that the Commission adopt firm guidelines for transmission providers to determine when the

[2628] Eversource Initial Comments at 34.

[2629] Public Interest Organizations Initial Comments at 45-47. *See also* Clean Energy Associations Initial Comments at 59; ENGIE Initial Comments at 10-11; SEIA Initial Comments at 38-39.

addition of a generating facility changes the service level to prevent discrimination against generating facilities based on their inclusion of hybrid resources.[2630]

1381. Pine Gate asks the Commission to require transmission providers to publish additional, consistent criteria regarding what changes to an interconnection request will and will not be deemed a material modification, and that transmission providers publish their determinations about previous modification requests.[2631] Pine Gate contends that this information, which certain RTOs/ISOs already provide to interconnection customers, will reduce the number of restudies, shorten overall interconnection queue processing timelines, and reduce costs. Pine Gate, SEIA, and Shell support establishing thresholds, arguing that providing guidance of what constitutes a material modification will provide certainty to both interconnection customers and transmission owners.[2632]

1382. OPSI asks the Commission to require transmission providers to publish guidance on technologies and generating facility designs that would qualify presumptively as minor system modifications.[2633] Indicated PJM TOs ask for "bright line" criteria (based on technical standards) for material modification to the extent possible, to narrow the scope of changes in a service request that need to be evaluated.[2634] However, Indicated

[2630] Environmental Defense Fund Reply Comments at 8-9.

[2631] Pine Gate Initial Comments at 47-49.

[2632] *Id.* at 48; SEIA Reply Comments at 23; Shell Initial Comments, app. A at ii.

[2633] OPSI Initial Comments at 9-10.

[2634] Indicated PJM TOs Initial Comments at 52-54; Indicated PJM TOs Reply

PJM TOs also argue that, in regions with large interconnection queues, the Commission should give transmission providers the flexibility to define "material modification," taking into account the cumulative impact of particular categories of requested modifications based on the transmission provider's past experience regarding the expected number of such requests.[2635]

1383. APS supports the proposal but requests guidelines regarding different technology types (e.g., increasing the size of a battery while also decreasing the size of a solar generating facility to keep the interconnection amount the same).[2636] APS recommends that each technology type be treated independently in relation to requests to increase or decrease the sizes in the original interconnection request or otherwise be deemed a material modification (e.g., if the characteristics of a storage component change, it should be considered a different request that may be a material modification).

1384. R Street similarly asks the Commission to consider standardized, non-discriminatory conditions that trigger a material change to an interconnection request, even if the service limit does not change, arguing that hybrid resources should not be penalized for their technology profile.[2637] R Street notes, for example, that adding an inverter-based generating facility to another such facility may not constitute a material

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Comments at 37.

[2635] Indicated PJM TOs Reply Comments at 39.

[2636] APS Initial Comments at 20.

[2637] R Street Initial Comments at 16.

change, but adding a natural gas turbine to a solar site, even with no increase to net output across the interconnection point, could create a material shift in interconnection facilities.

1385. NARUC asks the Commission to clarify the degree of flexibility transmission providers have in determining what constitutes a material reliability concern on the transmission system.[2638] Cypress Creek asks the Commission to further modify the current material modification definition to state that certain equipment changes are not material (e.g., changing solar modules, changing inverter models, adding storage capacity, or making minor adjustments to inverter performance) if planned export and import capacity remains the same and the technology changes comport with interconnection agreement requirements.[2639] ClearPath asks: (1) whether under the proposed definition a change in equipment that necessitates submitting new models and input data is a material modification; and (2) how equipment changes for non-synchronous resources will be treated under the proposed definition of material modification and the proposed deadlines.[2640]

1386. Ørsted supports the proposed definition of "material modification" but disagrees with imposing restrictions on when material modifications can be submitted (e.g., after

[2638] NARUC Initial Comments at 33-35.

[2639] Cypress Creek Initial Comments at 18-19.

[2640] ClearPath Initial Comments at 10.

the initial application).[2641] Ørsted asks the Commission to recognize that modifications may occur at various stages of the process to reflect the use of evolving technology or to meet federal or state requirements.[2642] Ørsted acknowledges transmission providers' time and effort to conduct studies associated with proposed modifications but states that there is also a need to balance the interests of the interconnection customer, as there are a number of reasons why changes to an interconnection request may be necessary and development time for resources must also be considered. Ørsted asserts that transmission providers' differing processes for assessing material modifications create regulatory uncertainty for interconnection customers seeking to develop generating facilities in different regions, which can have significant economic impacts for the generating facility.[2643] Ørsted states that, if the Commission chooses not to make the proposed change to the modification process, then, at a minimum, the Commission should encourage development of best practices that can be implemented by all the RTOs/ISOs with the goal of increasing efficiency and regulatory certainty.

1387. Shell asks the Commission to define the differences between "co-located additive," "co-located non-additive," and "hybrid" resources, and explains that these categories will allow transmission providers to develop proper criteria and business

[2641] Ørsted Reply Comments at 5 (citing PJM Initial Comments at 17).

[2642] *Id.* at 2.

[2643] *Id.* at 6-7.

practices governing additions and/or changes to pending interconnection requests.[2644] Shell argues that, because transmission providers inconsistently apply the methods they use to assess which issues qualify as being adverse material impacts, the Commission should more clearly define the scope of an "adverse material impact" to ensure that transmission providers consistently determine whether an interconnection request impacts equally or lower-queued interconnection customer(s) to a sufficient level of harm.

(2) Comments on Study Timeline

1388. With respect to the study timeline, while NARUC supports the proposal to require transmission providers to evaluate proposed generation additions within 60 calendar days because it is a reasonable amount of time, it suggests that the Commission allow some flexibility because planning regions and the industry may face challenges aligning resources and expertise with increasingly aggressive schedules to perform complex interconnection studies.[2645] Public Interest Organizations, on the other hand, argue that the 60-day timeline to perform an evaluation is critically important for continuing to reduce delays in interconnection queue processing.[2646] Cypress Creek supports the concept of expedited study if the request for a modification does not change the level of service, there is no impact on cost or timing of a request that is lower- or equally queued,

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[2644] Shell Initial Comments, app. A at ii.

[2645] NARUC Initial Comments at 33-35.

[2646] Public Interest Organizations Initial Comments at 45-47.

and it does not cause reliability concerns.[2647] Tri-State asks how the 60-day time frame would work with the cluster study process.[2648] PJM opposes the 60-day timeline.[2649]

(3) <u>Comments on Control Technologies</u>

1389. ENGIE suggests that including control technologies in the evaluation of the addition of a generating facility to an existing interconnection request should confirm the lack of impact on other interconnection customers.[2650] SEIA argues that transmission providers should be transparent about requiring specific types of control technologies to add an additional resource.[2651] Clean Energy Associations contend that hardware or software controls can also address, reliably and cost-effectively, concerns about the impact of the use or addition of energy storage on the reliable operation and delivery of energy (such as PJM's concern regarding studies for light load conditions).[2652]

(4) <u>Comments on Impacts of Storage in Charging Mode</u>

1390. Pine Gate states that the scope of the required studies for the addition of storage will vary depending on the proposed configuration of the resource, such as whether it

[2647] Cypress Creek Initial Comments at 18-19.

[2648] Tri-State Initial Comments at 30.

[2649] PJM Initial Comments at 51-53.

[2650] ENGIE Initial Comments at 11.

[2651] SEIA Initial Comments at 38-39.

[2652] Clean Energy Associations Reply Comments at 10-11.

charges from the grid.[2653] NV Energy states that any changes in the electrical characteristics of the storage system in charging mode versus generating mode are most likely negligible and unlikely to significantly impact studies.[2654]

1391. APS explains that, based on its experience, the introduction of new load (not electrical characteristics), such as storage charging from the grid in lieu of self-charging, which could require changes to the system overall, could affect the results of the existing study and other studies.[2655]

1392. Public Interest Organizations state that the transmission provider should study whether a storage generating facility's charging and discharging load profiles may impact the grid.[2656] Public Interest Organizations argue that the interconnection customer and transmission provider should work together to "identify the temporal and physical charging characteristics to be agreed upon," but that the Commission does not need to further assess the details of the storage generating facilities charging because those attributes will be tied to the unique properties of the transmission system at that location and assessed during the interconnection process to ensure that charging load and operational profiles do not adversely impact the system.

[2653] Pine Gate Initial Comments at 48.

[2654] NV Energy Initial Comments at 18.

[2655] APS Initial Comments at 21.

[2656] Public Interest Organizations Initial Comments at 45-47.

(5) Miscellaneous Comments

1393. PJM asks the Commission to restrict the ability to modify interconnection requests after the initial application by allowing (1) an interconnection customer to move its point of interconnection only in certain limited instances and (2) other specified modifications only at certain specified times to avoid restudies and study delays.[2657] PJM contends that there is no need to study the materiality of a change in an interconnection request's point of interconnection because each such change requires analysis and the application of engineering judgment, which takes time away from processing interconnection requests and performing the cluster study. PJM claims that interconnection customers making changes are really seeking to optimize their generating facilities mid-process rather than performing due diligence before entering the interconnection queue.

1394. With respect to the need for system impact studies, Illinois Commission argues that, although in some cases additional studies are necessary in response to a request to add a generating facility to an existing interconnection request to ensure reliability, transmission providers should minimize repeating system impact studies to the extent possible to avoid slowing down the interconnection queue.[2658] In response to the concern that evaluating modifications is time-consuming, Ørsted asks the Commission to allow

[2657] PJM Initial Comments at 17-18.

[2658] Illinois Commission Initial Comments at 13-14.

third-party consultants engaged by the interconnection customers to help inform any studies related to modifications to reduce the workload on RTO/ISO staff.[2659]

1395. PPL suggests that the transmission provider should assign an interconnection queue position to the proposed additional generating facility.[2660] PPL recommends the study of the original and additional interconnection request together in the initial phase of the interconnection process, and if they do not contribute to any network upgrades or require any interconnection facilities, PPL suggests they should be able to proceed directly to final agreements.

1396. Pine Gate states that, if addition of a grid-charging storage resource is deemed a material modification, the interconnection customer should be permitted to propose the addition of a non-grid-charging electric storage resource as an alternative.[2661] In order to reduce the burden on transmission providers, Pine Gate asks the Commission to permit interconnection customers to provide to transmission providers engineering analysis applying what Pine Gate suggests would be published engineering criteria to the requested modification and analyzing the impacts to other interconnection customers or reliability, with the transmission provider then validating the results and determining if the proposed modification is material.

[2659] Ørsted Reply Comments at 7.

[2660] PPL Initial Comments at 22.

[2661] Pine Gate Initial Comments at 47-49.

1397. Clean Energy Associations explain that if transmission providers study each component of co-located generating facilities separately, a wind or solar generating facility could obtain a faster study for ERIS while the co-located storage could get a more detailed study for NRIS.[2662] Clean Energy Associations assert that this flexibility would provide transmission providers more visibility during interconnection processes, reduce requests to retrofit generating facilities with additional co-located resources, and enable faster interconnection processes for component resources that will accept curtailment.

(d) Requests for Clarification and Flexibility

1398. MISO asserts that, if the Commission adopts the proposal, the Commission should modify the proposed requirement to allow the "proposed addition of a generating facility to an interconnection request as long as the interconnection customer does not request a change to the originally requested interconnection service level and the proposed addition to the generating facility is modeled the same way as the original generating facility."[2663]

1399. Clean Energy Associations ask the Commission to clarify whether (1) generating facility size reductions, which could result in upgrade costs being shifted to others in the same cluster, would be a material modification and (2) there is a reduction threshold that would trigger a material modification.[2664]

[2662] Clean Energy Associations Initial Comments at 59-61.

[2663] MISO Initial Comments at 108-12.

[2664] Clean Energy Associations Initial Comments at 64.

1400. Invenergy asks the Commission to clarify that its proposed requirement to evaluate requests to add a generating facility extends to requests for surplus interconnection service and that those requests cannot automatically be deemed a material modification.[2665] Invenergy argues that, when the surplus interconnection request is below the total original LGIA interconnection rights and determined a material modification, the interconnection customer should have the opportunity to mitigate the identified issue so that it is no longer a material modification.

1401. Equinor Wind seeks clarification that the proposed definition of material modification excludes changes that (1) occur on the interconnection customer's side of the point of interconnection and (2) do not alter the electrical output or electrical characteristics of a generating facility, adding that such changes should not be subject to the transmission provider's discretion or evaluation of whether they amount to a material modification.[2666] Equinor Wind argues that these clarifications will reduce uncertainty for interconnection customers and allow for some appropriate flexibility during generating facility development, particularly for offshore wind. Equinor Wind asserts that this clarification will not create reliability concerns because these changes do not have transmission system impacts.

1402. Indicated PJM TOs ask the Commission to clarify the relationship between the use of the term "material modification" in the *pro forma* LGIP and the term "materially

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[2665] Invenergy Initial Comments at 51-52.

[2666] Equinor Wind Reply Comments at 5-6.

modify" in NERC Reliability Standards FAC-001-3 (Facility Interconnection Requirements) and FAC-002-2 (Facility Interconnection Studies), asserting that the lack of clarity and overlap between the two terms could cause confusion and may result in additional delays to the interconnection process.[2667] UMPA asks the Commission to clarify that adding a generating facility includes technology changes beyond electric storage resources, such as changing from wind to solar.[2668]

1403. With respect to who performs the study to determine the impact of adding a generating facility to an existing interconnection request, NARUC argues that, because the reliable operation of the bulk-power system is at issue, the Commission should clarify that the transmission providers determine whether (1) the addition of a generating facility requires a full interconnection service study and (2) the interconnection customers in the same cluster (or subsequent clusters) could be adversely impacted.[2669] NARUC adds that the Commission should ensure that these processes are transparent, clearly communicated to interconnection customers, and allow interconnection customers to mitigate the impacts and revise their modifications requests.

1404. National Grid urges the Commission to allow ISO-NE and NYISO to maintain their processes that allow the transmission owner and RTO/ISO to evaluate the proposed

[2667] Indicated PJM TOs Initial Comments at 52-54 (noting NERC's pending petition to change the term from "materially modify" to "qualified change").

[2668] UMPA Initial Comments at 8-9.

[2669] NARUC Initial Comments at 33-35.

change and the RTO/ISO to make the final determination as to whether the change constitutes a material modification.[2670] Indicated PJM TOs argue that the final rule should have sufficient flexibility to allow PJM's proposed definition of "material modification" or permit PJM to obtain an independent entity variation for its proposed definition.[2671]

1405. Omaha Public Power asks the Commission to allow transmission providers to continue their existing processes of facilitating the use of newer technologies such as storage to promote the stability of these processes rather than using the proposed process on the NOPR.[2672]

iii. Commission Determination

1406. We adopt, with modifications, the NOPR proposal to revise section 4.4.3 of the *pro forma* LGIP to require transmission providers to evaluate the proposed addition of a generating facility at the same point of interconnection prior to deeming such an addition a material modification, if the addition does not change the originally requested interconnection service level. We modify the NOPR proposal regarding section 4.4.3 of the *pro forma* LGIP, as discussed in greater detail below, to: (1) remove the 60-calendar day requirement for assessment of material modification; (2) limit the requirement that the transmission provider analyze a request to add a generating facility to an existing

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[2670] National Grid Initial Comments at 40.

[2671] Indicated PJM TOs Initial Comments at 52-54.

[2672] Omaha Public Power Initial Comments at 13.

interconnection request solely to requests received prior to the interconnection customer's return of the executed facilities study agreement to the transmission provider; and (3) create an exception for transmission providers that employ fuel-based dispatch assumptions from these requirements.

1407. We find that the record demonstrates that automatically deeming a request to add a generating facility to an existing interconnection request to be a material modification creates a significant barrier to access to the transmission system[2673] and renders existing interconnection processes unjust and unreasonable. Such default treatment deters interconnection customers from proceeding with changes to a proposed generating facility that, after review, may be found not to be material, thereby reducing the number of generating facilities that can access the transmission system. This creates a barrier to the addition of a generating facility to an existing interconnection request that may improve the efficient use of the transmission system.

1408. We make several modifications to the NOPR proposal in response to concerns reflected in the record. First, we recognize that it may be difficult for some transmission providers to complete their material modification evaluations within 60 calendar days, depending on the details of their individual interconnection processes; therefore, we decline to adopt a 60-calendar day requirement. This preserves flexibility for

[2673] *See, e.g.*, AEE Initial Comments at 40-41; Public Interest Organizations Initial Comments at 45-47; SEIA Initial Comments at 38-39.

transmission providers to address modification requests as is most efficient with their overall interconnection queue processing.

1409. Second, we modify the NOPR proposal to limit when an interconnection customer may request to add a generating facility to an existing interconnection request without such a request automatically being deemed a material modification. We are persuaded by commenters' arguments that allowing requests for evaluation to occur at any point in the interconnection process could impede the ability of the transmission provider to timely process its interconnection queue.[2674] Thus, we modify the NOPR proposal, and transmission providers will only be required to evaluate whether a request to add a generating facility to an existing interconnection request is material if it is submitted before the interconnection customer returns the executed facilities study agreement to the transmission provider. Once the executed facilities study agreement is returned, the transmission provider may decide to automatically treat requests to add a generating facility to an existing interconnection request as material modifications without review.

1410. We clarify that interconnection customers may continue to request changes to proposed generating facilities at any time in the interconnection process. Transmission providers that choose to evaluate modification requests later in the interconnection process than required by this rule (i.e., after the interconnection customer returns the

[2674] *See, e.g.*, Indicated PJM TOs Initial Comments at 52-54; Indicated PJM TOs Reply Comments at 38; MISO Initial Comments at 108-112; PJM Initial Comments at 6.

executed facilities study agreement to the transmission provider) may continue to do so. This final rule does not address how transmission providers evaluate modification requests after the facilities study agreement, and thus transmission providers are not required to include their modification processes after the facilities study agreement in their compliance filing with this final rule.

1411. We acknowledge that, as stated by commenters, transmission providers that employ fuel-based dispatch assumptions, such as MISO, may experience challenges with the proposal because the interconnection study assumptions in a fuel-based dispatch model vary depending on the fuel type; thus a request to add a generating facility of a different fuel type to an existing interconnection request would always constitute a modification that would require a study, thereby affecting the interconnection costs or study timing for lower- or equally-queued interconnection customers.[2675] This type of request would most likely represent a material modification and would result in the loss of interconnection queue position under the tariff. Therefore, we modify the proposal to include an exception for transmission providers that use fuel-based dispatch assumptions in their interconnection studies.

1412. In response to EPSA's and Equinor Wind's request to provide a clearer standard definition of material modification,[2676] we note that we are not changing the definition of material modification in this rule and do not believe a more prescriptive definition of

[2675] *See, e.g.*, MISO Initial Comments at 108-12.

[2676] EPSA Initial Comments at 13; Equinor Wind Reply Comments at 5-6.

material modification is reasonable given the nuances in transmission providers' processes for assessing material modification, as described in the comments.[2677] With respect to NARUC's request to clarify the flexibility transmission providers have in determining what constitutes a material reliability concern on the transmission system,[2678] we clarify that this reform only requires transmission providers to evaluate interconnection modification requests. As stated above, it does not alter the definition of material modification. Transmission providers may continue to find requests to be material if they impact the cost or timing of an equally or lower-queued interconnection customers.

1413. Commenters request clarification about the requirements for demonstrating site control when submitting a modification request.[2679] In response, we clarify that, where a modification request to add a generating facility to an existing interconnection request requires the interconnection customer to adhere to a larger footprint to support a modified facility design, the interconnection customer must provide evidence of the required site control when submitting the modification request to the transmission provider. The requirements for site control that the interconnection customer must adhere to may depend on the timing of the request for the modification as well as the technology type of

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[2677] *See, e.g.*, National Grid Initial Comments at 40.

[2678] NARUC Initial Comments at 33-35.

[2679] *See, e.g.*, Indicated PJM TOs Initial Comments at 52.

the requested additional generating facility, as discussed in the site control portion of this rule.[2680]

1414. Indicated PJM TOs also request that the Commission clarify the relationship between the term "material modification" in the *pro forma* LGIP and the term "materially modify" in NERC Reliability Standard FAC-001-3.[2681] We find that this request to further define the relationship between the terms is outside of the scope of this rulemaking. As discussed above, this final rule does not alter the preexisting definition of a material modification. Moreover, we note that the Commission recently approved a change to the NERC FAC Reliability Standards to change "materially modify" to "qualifying change."[2682]

1415. ClearPath seeks clarification regarding equipment changes, specifically whether under the proposed definition of material modification**,** a change in equipment that necessitates submitting new models and input data is a material modification and how equipment changes for non-synchronous resources will be treated under the proposed definition of material modification and the proposed deadlines.[2683] We clarify that an

[2680] *See supra* Section III.A.6.b of this final rule.

[2681] Indicated PJM TOs Initial Comments at 52.

[2682] *See N. Am. Elec. Reliability Corp.*, 181 FERC ¶ 61,126 at P 9 (2022) (explaining that replacing materially modify with qualified change "removes the possibility of confusion with the Commission's defined term 'Material Modification' in its *pro forma* interconnection procedures and agreements").

[2683] ClearPath Initial Comments at 10.

equipment change, whether for synchronous or non-synchronous resources, that does not change the originally requested interconnection service level and does not qualify for evaluation under the transmission provider's technological change procedure must be evaluated by the transmission provider to determine if it is a material modification.

1416. Similarly, Equinor Wind seeks clarification that the proposed definition of material modification excludes changes that do not alter the electrical output or electrical characteristics of an interconnection request, suggesting that such changes should not be subject to the transmission provider's discretion or evaluation of whether they amount to a material modification.[2684] We note that the definition of material modification is based on whether changes have a material impact on the cost or timing of any interconnection request with an equal or lower interconnection queue position, and thus we decline to categorically exclude certain types of changes from the definition.

1417. Clean Energy Associations ask the Commission to clarify whether: (1) generating facility size reductions, which could result in upgrade costs being shifted to others in the same cluster, would be a material modification; and (2) there is a reduction threshold that would trigger a material modification.[2685] We clarify that, as per *pro forma* LGIP section 4.4.1, prior to the return of the cluster study agreement from the transmission provider to the interconnection customer, a decrease of up to 60% of electrical output (MW) must not be considered a material modification. In addition, per *pro forma* LGIP section 4.4.2,

[2684] Equinor Wind Reply Comments at 5-6.

[2685] Clean Energy Associations Initial Comments at 64.

prior to the return of the executed interconnection facilities study, an additional 15% decrease of electrical output of the proposed project must not be considered a material modification if the change occurred either through a decrease in plant size (MW) or a decrease in interconnection service level accomplished by applying transmission provider-approved injection-limiting equipment.

1418. Invenergy, in discussing both surplus interconnection and material modification, contends that in circumstances where a surplus interconnection request is below the total LGIA interconnection rights and determined to be a material modification, the interconnection customer should have the opportunity to mitigate identified issues such that there is no longer a material modification.[2686] We find this request to be outside the scope of this proceeding because the final rule is not proposing a process whereby interconnection customers may mitigate identified issues to avoid a material modification determination. In response to Invenergy's request to clarify that the proposed reforms to require evaluation of requests to add a generating facility extend to requests for surplus interconnection service, the Commission declines to make such a change. The surplus interconnection service process is separate from the material modification process, and the two processes should not be conflated.

1419. We decline to adopt firm guidelines that transmission providers will follow to determine what constitutes a material modification when a request to add a generating facility to an existing interconnection request involves adding co-located generating

[2686] Invenergy Initial Comments at 51.

facilities.[2687] The varying configurations and varying electrical characteristics that interconnection customers may propose through this process may alter how they impact equally or lower-queued interconnection customers, and therefore we find that transmission providers must retain flexibility to evaluate these requests.

c. Availability of Surplus Interconnection Service

i. Need for Reform and NOPR Proposal

1420. In the NOPR, the Commission noted that Order No. 845 established a surplus interconnection service process to enable a new interconnection customer to use the unused portion of an existing interconnection customer's approved interconnection service through the inclusion of an additional generating facility behind a single point of interconnection.[2688] The Commission also noted that Order No. 845 did not specify when a generating facility is considered to be "existing," and preliminarily found that limiting the use of surplus interconnection service to only interconnection customers that have achieved commercial operation may be unjust, unreasonable, and unduly discriminatory or preferential.[2689]

[2687] We consider Shell's request for the Commission to define the differences between "co-located additive," "co-located non-additive," and "hybrid" resources, as well as Shell's request to specify the approach to charging energy, to be included among the requests for firm guidelines.

[2688] NOPR, 179 FERC ¶ 61,194 at P 262.

[2689] *Id.* P 263.

1421. The Commission proposed to revise the *pro forma* LGIP to require transmission providers to allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA.[2690]

ii. Comments

(a) Comments in Support

1422. The vast majority of commenters on this topic either support or do not oppose the proposal regarding surplus interconnection service, though some seek various clarifications.[2691] MISO states that surplus interconnection requests are the proper method for interconnection customers to add storage or a different generating facility fuel source to an interconnection request for an unbuilt generating facility[2692] and suggests that the Commission limit when the transmission provider must tender a surplus interconnection agreement to the interconnection customer to prevent a surplus interconnection agreement from being tendered prior to the original interconnection

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[2690] *Id.* P 264.

[2691] AEE Initial Comments at 41; AEP Initial Comments at 5, 44-45; APS Initial Comments at 21; Clean Energy Associations Initial Comments at 61; CREA and NewSun Initial Comments at 91; Elevate Initial Comments at 11-12; Enel Initial Comments at 79; Eversource Initial Comments at 34; Iowa Commission Initial Comments at 4; NARUC Initial Comments at 36; National Grid Initial Comments at 41; NextEra Initial Comments at 37; NRECA Initial Comments at 44; Omaha Public Power Initial Comments at 13; PacifiCorp Initial Comments at 40; SEIA Initial Comments at 39; Shell Initial Comments at 36; SPP Initial Comments at 24.

[2692] MISO Initial Comments at 113-14.

agreement becoming effective. MISO explains that its generator interconnection procedures allow for a surplus interconnection request to be made during the processing of the interconnection queue and adds that MISO is not required to tender a surplus interconnection agreement until the original interconnection agreement has become effective because a surplus interconnection agreement is a derivative of the original interconnection agreement. According to MISO, under the proposed reform, the surplus interconnection agreement could be tendered prior to the original interconnection agreement becoming effective if the original interconnection agreement is filed unexecuted and becomes the subject of a disputed proceeding.

(b) <u>Comments in Opposition</u>

1423. Some commenters either argue that the NOPR proposal is inappropriate for their situation or oppose it outright, in some cases arguing against the underlying concept of surplus interconnection service. For instance, NYISO asserts that it does not provide for the use of "surplus" interconnection service and the Commission has previously granted NYISO an independent entity variation from the surplus interconnection service requirement.[2693] NYISO asserts that this independent entity variation remains just and reasonable and accomplishes the purposes of Order No. 845 and the instant NOPR to

[2693] NYISO Initial Comments at 49 (citing *N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,117, at P 98 (2020)).

make it easier for proposed generating facilities to interconnect without costly upgrades.[2694]

1424. ISO-NE states that allowing for co-location of generating facilities meets the need of allowing surplus interconnection service to be available after executing an LGIA, rendering the proposed reform unnecessary.[2695] ISO-NE explains that, unless the existing generating facility is already commercial, there is no unused capability available at the point of interconnection. ISO-NE asserts that, to the extent the interconnection customer wants to co-locate generating facilities, it should be required to propose that as part of the original interconnection request.

1425. CAISO disagrees that allowing an interconnection customer to request surplus interconnection service after the original interconnection customer executes an LGIA would enable interconnection customers with unused interconnection capacity to let other generating facilities use that capacity earlier than allowed.[2696] CAISO contends that interconnection customers do not request to use surplus interconnection service, and further reform is unlikely to have much effect because surplus interconnection service is unavailable independent of the Commission's definition. CAISO asserts that interconnection customers do not oversize their interconnection capacity; therefore, other

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[2694] *Id.* at 50.

[2695] ISO-NE Initial Comments at 40.

[2696] CAISO Initial Comments at 32-33.

interconnection customers cannot avail themselves of any "surplus" because it is already subscribed.

1426. PJM asserts that the current surplus interconnection service construct provides no value due to the challenges inherent in assessing the dynamic response associated with adding a surplus generating facility to the system while not infringing on the rights of the interconnection customers in the interconnection queue or available "headroom."[2697] Therefore, PJM contends that it sees no benefit in expanding its application and that PJM's current surplus interconnection service is rarely used. PJM asserts that surplus interconnection service imposes overhead costs without providing value to interconnection customers wishing to interconnect.

1427. In response to PJM and CAISO's comments, SEIA replies that both PJM and CAISO take an overly narrow approach to surplus interconnection service and that past use of surplus interconnection service should not bar making the service available to future requests to add storage to a generating facility.[2698]

(c) <u>Comments on Specific Proposal</u>

1428. Other commenters argue that, at least in some situations, surplus interconnection service should be available even earlier than proposed in the NOPR. For instance, Ameren asserts that there is no need to restrict the request to an executed, or requested

[2697] PJM Initial Comments at 65.

[2698] SEIA Reply Comments at 23-25.

unexecuted, LGIA.[2699] Ameren contends that, under the Commission's proposal, MISO and the interconnection customer would have finalized the network upgrades and system impact study only to go back to assess what surplus interconnection capacity would have been available. Therefore, Ameren asks the Commission to allow for regional flexibility. Omaha Public Power likewise recommends that the Commission allow existing transmission provider processes that are facilitating new technologies to continue.[2700]

1429. Pine Gate favorably cites MISO's process for surplus interconnection service and asserts that the Commission should expand its current proposal to permit interconnection customers to access the surplus interconnection service process upon completion of the cluster restudy phase.[2701] Invenergy states that the Commission should permit requests for surplus interconnection service after an interconnection request has an executed facilities study agreement.[2702] Invenergy contends that the Commission could further clarify that an LGIA must be in place for the initial facility before any LGIA for the surplus interconnection service can be tendered. Invenergy asserts that, if the Commission does not modify the NOPR, it should clarify that transmission providers like MISO that have existing practices under which surplus interconnection service can be requested earlier in the process may continue those existing practices in compliance

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[2699] Ameren Initial Comments at 28.

[2700] Omaha Public Power Initial Comments at 13.

[2701] Pine Gate Initial Comments at 49-50.

[2702] Invenergy Initial Comments at 50.

filings after any final rule may become effective. Invenergy also states that the Commission should reinforce its commitment in Order No. 845 that surplus interconnection service is available up to the maximum level allowed under the original interconnection agreement.[2703] According to Invenergy, some transmission providers significantly limit an interconnection customer's surplus interconnection rights by deeming an otherwise permitted request a material modification except in the limited situation of direct current (DC)-coupled behind-the-meter storage, which effectively precludes surplus interconnection service in all other circumstances under a standard that is not well-defined or explained.

1430. Elevate encourages the Commission to consider modifying the duration of the period in which an interconnection customer taking surplus interconnection service can continue to operate following the original, host generating facility's retirement.[2704] Elevate contends that, although an interconnection customer taking surplus interconnection service may operate for up to a year following the original generating facility's retirement, a one-year period is too short when it may take four years or more to navigate the interconnection process. According to Elevate, a surplus interconnection customer should be able to operate sufficiently long following the original generating facility's retirement that it has the ability to obtain permanent interconnection service

[2703] *Id.* at 50-51 (citing Order No. 845, 163 FERC ¶ 61,043 at P 475).

[2704] Elevate Initial Comments at 11-12.

through the submission of a new interconnection request.[2705] Elevate contends that this will ensure that generation capacity that has been fully constructed and is contributing to system reliability is not unnecessarily forced offline due to interconnection queue backlogs beyond their control.

(d) <u>Requests for Clarification</u>

1431. Shell contends that the Commission should clarify that transmission providers cannot deny surplus interconnection capacity except where (1) the total amount of interconnection service, measured in MW, at the point of interconnection has increased, or (2) there will be a reliability risk to the relevant transmission system.[2706]

1432. NARUC asks the Commission to clarify in the *pro forma* LGIP that an interconnection customer that has been fully studied and has an executed LGIA, or has filed an unexecuted LGIA, should be considered an existing facility for purposes of surplus interconnection service.[2707] NARUC asserts that this clarification will increase efficiency in interconnection queues throughout the planning regions and ensure that available interconnection capacity can be used efficiently.

1433. Enel requests that the Commission specify that parallel, simultaneous operation and injection of two distinct, alternating current (AC)-coupled generating facilities is an acceptable configuration for surplus interconnection service so long as the total injection

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[2705] *Id.* at 12 (citing Order No. 845, 163 FERC ¶ 61,043 at P 506).

[2706] Shell Initial Comments at 36.

[2707] NARUC Initial Comments at 36.

of energy at the point of interconnection does not exceed the interconnection service level.[2708]

1434. APS and PacifiCorp ask the Commission to clarify that no surplus can be provided if the LGIA of the original interconnection request is suspended.[2709] PacifiCorp explains that, if the underlying LGIA is suspended, then there is no guarantee that the facilities required for interconnection will be installed.[2710] APS further asserts that, if an interconnection customer requests to go into suspension after a surplus request is granted, then that would also require the surplus interconnection to be suspended.[2711] PacifiCorp asserts that any work the transmission provider were to undertake relating to the surplus interconnection service may be wasted effort if the LGIA never comes out of suspension.[2712] PacifiCorp asks the Commission to clarify that, if the original surplus interconnection request exceeds its permitted suspension period, both the original LGIA and any surplus interconnection service shall be terminated.

1435. Idaho Power requests clarification as to whether the Commission intends for the surplus interconnection service process to be used for an interconnection customer that owns a generating facility, either in-service or with an executed interconnection

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[2708] Enel Initial Comments at 79.

[2709] APS Initial Comments at 21; PacifiCorp Initial Comments at 40.

[2710] PacifiCorp Initial Comments at 40.

[2711] APS Initial Comments at 21.

[2712] PacifiCorp Initial Comments at 40-41.

agreement, to add energy storage after the interconnection agreement is executed, or if the Commission intends for these additions to be evaluated under *pro forma* LGIA article 5.19 (Modification).[2713]

iii. <u>Commission Determination</u>

1436. We adopt the NOPR proposal to revise section 3.3.1 of the *pro forma* LGIP to require transmission providers to allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA.

1437. We find, based on the record, that this reform will enable interconnection customers with unused interconnection service to let other generating facilities use that interconnection service earlier than is currently allowed and, therefore, increases overall efficiency of the interconnection queue.[2714] Because we find this reform to be just and reasonable, to remedy the unjust and unreasonable rates caused by the limited ability to use surplus interconnection service today and ensure that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner, we decline to adopt alternative proposals suggested by commenters.

1438. We find unpersuasive the comments from various RTOs/ISOs opposing the NOPR proposal.[2715] To the extent that they oppose the surplus interconnection service process

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[2713] Idaho Power Initial Comments at 14.

[2714] *See, e.g.*, AEE Initial Comments at 41.

[2715] CAISO Initial Comments at 32-33; ISO-NE Initial Comments at 40; NYISO

approved by the Commission in Order No. 845, we find their arguments to be a collateral attack on the Commission's findings in Order No. 845 and irrelevant for purposes of determining whether the instant proposal is just and reasonable. Further, consistent with the NOPR, we continue to find that expanding the availability of surplus interconnection service beyond those entities that have achieved commercial operation will address the Commission's concerns regarding undue restrictions on access to this surplus interconnection service,[2716] thereby making it available to a broader group of potential interconnection customers and achieving the efficiencies discussed above.

1439. We are also not persuaded by either Pine Gate's or Ameren's arguments[2717] to alter the NOPR proposal to require transmission providers to allow interconnection customers to access the surplus interconnection service process prior to the LGIA phase or Invenergy's argument to allow requests for surplus interconnection service once there is an executed facilities study agreement.[2718] We find that allowing interconnection customers to access the surplus interconnection service process once the original interconnection customer obtains an executed LGIA, or requests the filing of an unexecuted LGIA, is appropriate because prior to that stage, the network upgrades

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Initial Comments 49-50; PJM Initial Comments at 65.

[2716] NOPR, 179 FERC ¶ 61,194 at P 263.

[2717] Ameren Initial Comments at 28; Pine Gate Initial Comments at 50.

[2718] Invenergy Initial Comments at 49.

necessary to create the identified amount of surplus interconnection service may not have been fully identified, let alone begun the process of being placed into service.

1440. In response to APS's and PacifiCorp's requests for clarification regarding suspensions,[2719] we clarify that: (1) if the LGIA of the original interconnection request is suspended, then any submitted requests for surplus interconnection service are likewise suspended, and new requests for surplus interconnection service may not be submitted, until after the suspension is lifted; and (2) if the original LGIA is terminated, including for exceeding the three-year suspension period (pursuant to *pro forma* LGIA article 5.16), any related surplus interconnection service allowed as a result of the original LGIA will be terminated because surplus interconnection service is dependent upon the underlying interconnection service used by existing generating facilities.

1441. In response to NARUC's request to clarify that an interconnection customer that has been fully studied and has an executed LGIA, or that has requested the filing of an unexecuted LGIA, should be considered an existing facility for purposes of surplus interconnection service, we decline to make such clarification, but reiterate that where an interconnection customer has executed the LGIA, or requested that the LGIA be filed unexecuted, interconnection customers may submit surplus interconnection service requests to the transmission provider.

[2719] APS Initial Comments at 21; PacifiCorp Initial Comments at 40-41.

1442. We find that Enel's and Shell's respective requests[2720] for clarification regarding establishing parameters on surplus interconnection service are outside the scope of this proceeding because this final rule is not proposing to modify eligibility for surplus interconnection service as established in Order No. 845.

1443. We also find that Elevate's request[2721] for the Commission to modify the duration in which an interconnection customer taking surplus interconnection service can continue to operate following the original, host generating facility's retirement is outside the scope of this proceeding because this final rule is not proposing to modify the length of time for which surplus interconnection service may be provided after the original generating facility retires.

1444. In response to Idaho Power's request for clarification regarding whether the Commission intends for the surplus interconnection service process to be used for an interconnection customer that owns a generating facility with an executed or unexecuted LGIA to later add energy storage,[2722] the answer depends upon how the energy storage facility will be used. If, for example, it is used only to firm up the underlying generating facility (e.g., a wind or solar power plant) without ever injecting in excess of the original interconnection service level, then surplus interconnection service may be used.[2723] If, on

[2720] Enel Initial Comments at 79; Shell Initial Comments at 36.

[2721] Elevate Initial Comments at 11-12.

[2722] Idaho Power Initial Comments at 14.

[2723] *See* Order No. 845, 163 FERC ¶ 61,043 at P 472 ("[S]urplus interconnection service cannot exceed the total interconnection service already provided by the original

the other hand, the new energy storage facility and the existing generating facility will be configured to inject together and exceed the original interconnection service limit, then surplus interconnection service may not be used.

1445. In response to Invenergy's requests,[2724] we clarify that the original interconnection customer must have an LGIA in place, either executed or requested to be filed unexecuted with the Commission, prior to tendering any LGIA for surplus interconnection service. With respect to Invenergy's request for flexibility for transmission providers that currently allow requests for surplus interconnection service before the LGIA phase, we note that transmission providers can propose deviations from the requirements adopted in this final rule and demonstrate how those deviations satisfy the standards discussed in Section IV of this final rule, which the Commission will consider on a case-by-case basis.

1446. In response to Invenergy's request to clarify that proposed reforms to require evaluation of requests to add a generating facility to an interconnection request extend to requests for surplus interconnection service, we clarify that the revisions to the modification process do not extend to the surplus interconnection service process. We note that the modification process revisions would be used by an interconnection customer while undergoing the interconnection study process, whereas the surplus interconnection process revisions would be used after the interconnection study process is

interconnection customer's LGIA.").

[2724] Invenergy Initial Comments at 50.

complete and the interconnection customer has an executed LGIA, or an unexecuted and filed LGIA.

1447. Invenergy requests that the Commission reiterate and reinforce its commitment in Order No. 845 that surplus interconnection service is available up to the maximum level allowed under the original interconnection agreement. Invenergy contends that, when the surplus interconnection service request is below the total LGIA interconnection rights and determined to be a material modification, the interconnection customer should have the opportunity to mitigate identified issues such that there is no longer a material modification. We decline Invenergy's request because the final rule does not address revisions to how the surplus interconnection service process is conducted; rather, the final rule addresses when a request for surplus interconnection service may be submitted.

d. Operating Assumptions for Interconnection Studies

i. Need for Reform and NOPR Proposal

1448. In the NOPR, the Commission stated that, as newer technologies with operating parameters that differ from traditional generation seek to interconnect, it is necessary for transmission providers to use assumptions that accurately reflect "the operating parameters of electric storage resources and co-located resources containing electric storage resources (including hybrid resources) so that the unique operating characteristics of such resources are taken into account during the generator interconnection process."[2725] The Commission stated that, because the *pro forma* LGIP includes only

[2725] NOPR, 179 FERC ¶ 61,194 at P 279.

general requirements regarding the operating assumptions for generating facilities in interconnection studies, it was concerned that "electric storage resources, and co-located resources containing electric storage resources, may be studied under inappropriate operating assumptions that result in assigning unnecessary network upgrades and increased costs to interconnection customers."[2726] The Commission therefore preliminarily found that "the lack of realistic operating assumptions used in interconnection studies for electric storage resources and co-located resources containing electric storage resources (including hybrid resources) can result in excessive and unnecessary network upgrades and may hinder the timely development of new generation, thereby stifling competition in the wholesale markets, and resulting in rates, terms, and conditions that are unjust and unreasonable."[2727] Further, the Commission preliminarily found that "the lack of appropriate operating assumptions used in interconnection studies may present an unduly discriminatory or preferential barrier to the interconnection of electric storage resources and co-located resources containing electric storage resources (including hybrid resources)."[2728]

1449. The Commission proposed to revise the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use "operating assumptions for interconnection studies that reflect the proposed operation of an electric storage

[2726] *Id.*

[2727] *Id.*

[2728] *Id.*

resource or co-located resource containing an electric storage resource (including hybrid resources)—i.e., whether the interconnecting resource will or will not charge during peak load conditions, unless good utility practice, including applicable reliability standards, otherwise require the use of different operating assumptions."[2729] The Commission noted that, under this proposed reform, such operating assumptions shall be proposed by the interconnection customer as part of its initial interconnection request.

1450. The Commission further proposed that such operating assumptions must be "reasonably representative of the likely behavior of an electric storage resource or co-located resource containing an electric storage resource (including hybrid resources) and, in cases where available, consistent with the historical performance of such resources in the relevant geographic area."[2730] Further, to help facilitate alignment between as-studied and real-world conditions, the Commission proposed to allow transmission providers to "hold interconnection customers to the intended operation of their electric storage resource or co-located resource containing an electric storage resource (including hybrid resources) by: (1) memorializing these operating restrictions in the interconnection customer's LGIA; and (2) requiring control technologies (software and/or hardware) in cases where appropriate, such as for electric storage that wishes to limit its operations, with such protection devices included in Appendix C of the LGIA."[2731] The Commission

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[2729] *Id.* P 280.

[2730] *Id.*

[2731] *Id.*

noted that, "if the interconnection customer fails to operate its electric storage resource or co-located resource containing an electric storage resource (including hybrid resources) in accordance with these conditions as memorialized in the LGIA, the interconnection customer may be considered in breach and the transmission provider may pursue termination pursuant to article 17 of the LGIA."[2732] Additionally, the Commission proposed to "require that any transmission provider that requires electric storage resources or co-located resources containing an electric storage resource (including hybrid resources) to install control technologies to publicly post a list of acceptable control technologies."[2733] Furthermore, the Commission proposed revisions to the description of the ERIS and NRIS studies in sections 3.2.1.2. and 3.2.2.2 of the *pro forma* LGIP to accommodate this proposed reform.

1451. The Commission proposed to require that interconnection customers clearly communicate to the transmission provider "the expected operating patterns of the electric storage resource, or co-located resource containing an electric storage resource (including hybrid resources)."[2734] In addition, for "the electric storage resource or co-located resource containing an electric storage resource (including hybrid resources) to be studied, the Commission proposed to require the interconnection customer to specify, as part of its initial interconnection request, the ancillary services that it would or would not

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[2732] *Id.*

[2733] *Id.*

[2734] *Id.* P 281.

provide so that the proper operating assumptions may be made in interconnection studies."[2735] Under the Commission's proposal, regardless of any changes to operating assumptions, "all electric storage resources, or co-located resources containing an electric storage resource (including hybrid resources) would be required to continue to meet all requirements in the *pro forma* LGIP and *pro forma* LGIA, as well as all applicable reliability standards."[2736]

1452. The Commission noted that, under this proposed reform, each transmission provider's operating assumptions used in their interconnection studies must take into consideration the services that the generating facility would provide and the timing of such services, as applicable.[2737] The Commission further noted that this could be done in a variety of ways, and the transmission provider would have flexibility to consider services as best fits its transmission system.

1453. The Commission proposed to clarify that "this proposed reform to study electric storage resources, or co-located resources containing an electric storage resource (including hybrid resources) according to their planned operating assumptions at the request of the interconnection customer as part of its initial interconnection request is intended to mean the operating assumptions for withdrawals of energy (e.g., the charging

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[2735] *Id.*

[2736] *Id.*

[2737] *Id.* P 282.

of an energy storage resource) in interconnection studies."[2738] The Commission proposed to require that the interconnection customer include in its initial interconnection request any operating assumptions for withdrawals of energy to be used by the transmission provider in interconnection studies.

1454. The Commission sought comment on whether the Commission should expand this reform to address operating assumptions for additional generating facility technologies that may currently be inaccurately modeled, such as variable energy resources.[2739] For example, the Commission sought comment on whether to expand this proposal to specify only that, at the interconnection customer's request, a transmission provider must not study generating facilities in ways that are not physically possible, for example studying a solar resource as producing energy at night, or a wind resource as producing maximum energy during low wind seasons, or other circumstances wherein any resource is studied in ways that are not physically possible, subject to the same proposed requirement that the generating facility be equipped with sufficient control technology, such as special protection systems, and/or subject to penalties for deviating from dispatch. The Commission sought comment on whether other operating assumptions, in addition to the assumption that electric storage resources withdraw energy during peak load periods, should be considered as part of this proposed reform.

[2738] *Id.* P 285.

[2739] *Id.* P 286.

1455. The Commission sought comment on how to define the study parameters (e.g., should the Commission define the peak load period and/or net peak load during which transmission providers must not study a generating facility as withdrawing energy, and if so how).[2740]

1456. The Commission also sought comment on "whether, and if so how, to define firm and non-firm charging for electric storage resources and require transmission providers to define study criteria and possible ways to interconnect related to both firm and non-firm charging."[2741] The Commission sought comment on whether providing such options would improve the effectiveness of this proposed reform and whether there would be other consequences of implementing such an approach. With respect to the definition of firm and non-firm charging, the Commission sought comment on whether to: "(1) define firm charging service as interconnection service that allows the interconnection customer to be eligible to receive electric energy in a manner comparable to a transmission provider's load; and (2) define non-firm charging service as interconnection service that allows the interconnection customer to be eligible to receive electric energy using the existing firm or non-firm capacity of the transmission system on an 'as available' basis, noting that in an RTO/ISO with market-based congestion management, a generating

[2740] *Id.* P 287.

[2741] *Id.* P 288.

facility with non-firm charging service must respond to the RTO's/ISO's dispatch instructions, including curtailment to manage congestion."[2742]

ii. Comments

(a) Comments in Support

1457. Many commenters support the Commission's proposal to revise the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located resource containing an electric storage resource (including hybrid resources)—i.e., whether the interconnecting generating facility will or will not charge during peak load conditions, unless good utility practice, including applicable reliability standards, otherwise require the use of different operating assumptions.[2743]

[2742] *Id.*

[2743] ACE-NY Initial Comments at 14-15; AEE Initial Comments at 41-42; AES Clean Energy Initial Comments at 24; Alliant Energy Initial Comments at 8; Bonneville Initial Comments at 22-23; CESA Initial Comments at 14-15; Clean Energy Associations Initial Comments at 52; Clean Energy Associations Reply Comments at 10; CREA and NewSun Initial Comments at 91-92; Cypress Creek Initial Comments at 9; Environmental Defense Fund Initial Comments at 6; Environmental Defense Fund Reply Comments at 8-9; ELCON Initial Comments at 10; Elevate Initial Comments at 13; Interwest Reply Comments at 15; Longroad Reply Comments at 10-12; Microgrid Resources Initial Comments at 6; NARUC Initial Comments at 37; NextEra Initial Comments at 36; NESCOE Reply Comments at 18; NRECA Initial Comments at 10, 44; NY Commission and NYSERDA Initial Comments at 10; Pine Gate Initial Comments at 51; Public Interest Organizations Initial Comments at 47; R Street Initial Comments at 16; SEIA Initial Comments at 40; Shell Initial Comments, app. A at iii; Union of Concerned Scientists Reply Comments at 9-10.

1458. Many commenters agree with the Commission that the lack of realistic operating assumptions used in interconnection studies for electric storage resources and co-located resources containing electric storage resources (including hybrid resources) can result in excessive and unnecessary network upgrades and hinder the timely development of new generation, thereby stifling competition in the wholesale markets, and resulting in rates, terms, and conditions that are unjust and unreasonable.[2744] These commenters also agree that using unrealistic operating assumptions in interconnection studies creates an unduly discriminatory or preferential barrier to the interconnection of electric storage resources and co-located resources containing electric storage resources (including hybrid resources).

1459. Many commenters agree with the Commission that the assumptions used in interconnection studies for the charging of electric storage resources should closely resemble the expected "real-world" operation of such resources.[2745] For example, NextEra asserts that operating assumptions should reflect the rational economic dispatch of electric storage and co-located resources and that interconnection customers with

[2744] AEE Initial Comments at 42; Alliant Energy Initial Comments at 8; Clean Energy Associations Initial Comments at 52-53; Hydropower Commenters Initial Comments at 21-22; Longroad Reply Comments at 10-12; NARUC Initial Comments at 36-37; NESCOE Reply Comments at 18; Pine Gate Initial Comments at 51, 54; Public Interest Organizations Initial Comments at 47; rPlus Initial Comments at 6; SEIA Initial Comments at 40; SEIA Reply Comments at 27.

[2745] Alliant Energy Initial Comments at 8; APPA-LPPC Initial Comments at 29; NextEra Initial Comments at 36-37; NY Commission and NYSERDA Initial Comments at 10; Pine Gate Initial Comments at 51; Shell Initial Comments, app. A at iii.

electric storage resources should be allowed to request a lower maximum allowed charging rate in place of being assigned network upgrade cost allocations.[2746] Shell asserts that parameters used to study storage should consider market conditions.[2747]

1460. Many commenters argue that assuming in an interconnection study that an electric storage resource will withdraw energy during peak demand similar to firm end-use customer demand fails to recognize the real-time attributes of electric storage resources, such as the ability to respond within seconds to prices and dispatch signals from the transmission provider.[2748] For example, NARUC and NESCOE argue that studying electric storage resources using worst-case operating assumptions, such as withdrawing energy during peak demand, ignores the real-time attributes and benefits of these technologies, such as their ability to respond within seconds to prices and dispatch signals from transmission providers and inject electricity during peak demand conditions.[2749] Further, Union of Concerned Scientists asserts that modeling storage as charging during times of peak demand penalizes interconnection customers for trying to locate electric storage resources in places where they are most needed (e.g., load pockets) because the

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[2746] NextEra Initial Comments at 37.

[2747] Shell Initial Comments, app. A at iii.

[2748] Clean Energy Alliance Initial Comments at 14-15; NARUC Initial Comments at 37; PacifiCorp Initial Comments at 41; Pattern Energy Initial Comments at 12; Pine Gate Initial Comments at 51; SEIA Initial Comments at 40; Union of Concerned Scientists Reply Comments at 10-11.

[2749] NESCOE Reply Comments at 18 (citing NARUC Initial Comments at 36-37).

study inappropriately models electric storage resources as contributing to the problem of transmission congestion rather than relieving it.[2750] AEP argues that some electric storage resources do occasionally charge during peak demand; however, AEP has no objection to electric storage resources being studied under a certain set of operating conditions as long as operating restrictions are imposed through interconnection agreements and the resource owner/operator recognizes that it must abide by dispatch orders and bear the consequences of any limitations on its operation that result in penalties.[2751]

(b) <u>Comments in Opposition</u>

1461. Some commenters argue that the proposed reform is overly burdensome on transmission providers and could add time and complexity to the interconnection process.[2752] For example, NYISO opposes the proposed reform, arguing that it would not streamline the interconnection study process and instead would add significantly more complexity to the process and increase the time required to complete studies.[2753]

[2750] Union of Concerned Scientists Reply Comments at 10-11.

[2751] AEP Initial Comments at 46-47.

[2752] Avangrid Initial Comments at 35; Enel Initial Comments at 74; ISO-NE Initial Comments at 40; NYISO Initial Comments at 51; PacifiCorp Initial Comments at 41-42; PJM Initial Comments at 67; Southern Initial Comments at 33.

[2753] NYISO Initial Comments at 51.

1462. Some commenters oppose the proposed reform due to reliability concerns.[2754] PJM argues that the proposal would be extremely difficult to police and enforce and would not guarantee that units will operate within their studied parameters, putting PJM at operational risk.[2755] Southern opposes the proposed reform, stating that transmission providers are ultimately responsible for planning for the safety and reliable operation of their transmission systems, which includes standard assumptions for interconnection studies.[2756] Southern contends that it may be viable to provide an information-only scenario using the assumptions provided by the interconnection customer, but it would not be just and reasonable to allow interconnection customers to dictate the study assumptions for their electric storage, hybrid, or co-located resources. NYISO asserts that its interconnection studies are designed to capture extreme system scenarios to best maintain the reliability of the system and to be prepared for rare extreme conditions and without such planning, the interconnection studies could fail to identify essential non-local network upgrades.[2757] SDG&E argues that the reform may introduce undue risk into the interconnection study process and could lead to the transmission system being operated in an unstudied/unplanned state.[2758]

[2754] *Id.* at 67; SDG&E Initial Comments at 8; Southern Initial Comments at 33.

[2755] PJM Initial Comments at 67.

[2756] Southern Initial Comments at 33.

[2757] NYISO Initial Comments at 51.

[2758] SDG&E Initial Comments at 7.

1463. However, several commenters disagree that the proposed reform will introduce undue risk into the interconnection study process and real-time operations.[2759] CESA asserts that many transmission providers continue to use historical planning standards that do not consider the capability of advanced firmware and software controls to dispatch resources in accordance with operating assumptions that can provide much needed additional capacity to the transmission system, which may result in continued delays and inefficiencies in the interconnection process.[2760]

1464. NARUC suggests that, in RTO/ISO regions, independent market monitors may be well-positioned to track deviations from proposed operational limits in real-time operations.[2761] For non-RTO/ISO regions, NARUC contends that it may be appropriate for an independent transmission monitor or NERC regional reliability entity to serve in such a role.

(c) <u>Comments on Specific Proposal</u>

1465. Some commenters support the flexibility that the proposed reform provides on the basis that it would allow for better use of the transmission system or help facilitate the interconnection process while still allowing for adequate controls.[2762] NRECA cautions,

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[2759] AEE Initial Comments at 41-42; CESA Reply Comments at 10 (citing SDG&E Initial Comments at 7); Clean Energy Associations Initial Comments at 58; R Street Initial Comments at 16.

[2760] CESA Reply Comments at 10.

[2761] NARUC Initial Comments at 38.

[2762] APS Initial Comments at 22; Cypress Creek Initial Comments at 9; NRECA

however, that such flexibility should not come at the expense of the NOPR's overall goal of reducing speculative interconnection requests, withdrawals, and restudies.[2763] APS also believes that operating assumptions used in interconnection studies should be limited to factors that can be automatically controlled by the interconnection customer; otherwise, system issues may occur when interconnection facilities are operating outside of the assumptions used in the studies.[2764] Although AEP generally supports the proposed reform because interconnection studies should be as accurate as possible, AEP notes that using operating assumptions provided by the interconnection customer may complicate studies and thus realistic study time frames must be adopted.[2765]

1466. Many commenters support the proposal to allow transmission providers to require the use of controls to ensure compliance with planned operation.[2766] Clean Energy Associations argue that electric storage resources are controllable with a level of precision and speed unparalleled by conventional generating facilities, which provides transmission owners and providers and interconnection customers with new opportunities

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Initial Comments at 10, 44; rPlus Initial Comments at 6.

[2763] NRECA Initial Comments at 44.

[2764] APS Initial Comments at 22.

[2765] AEP Initial Comments at 45.

[2766] AEE Initial Comments at 41-42; APS Initial Comments at 22; Bonneville Initial Comments at 23; Clean Energy Associations Initial Comments at 52-58; ELCON Initial Comments at 10; Eversource Initial Comments at 36; NARUC Initial Comments at 38; PPL Initial Comments at 23; Public Interest Organizations Initial Comments at 49-50; SEIA Initial Comments at 40.

to accommodate transmission system reliability needs and efficiently use scarce transmission interconnection capacity.[2767] Clean Energy Associations assert that the proposed reform would acknowledge the fact that electric storage resources are highly controllable through hardware and software controls.[2768] SEIA asserts that power control systems, which electronically limit or control steady state currents to a programmable limit, can ensure that electric storage resources follow operating assumptions, and that their use is growing.[2769]

1467. Idaho Power states that it currently has a generator control and monitoring technology that can be leveraged for monitoring and controlling electric storage charging.[2770] However, Idaho Power asserts that it will need to implement a control scheme for operators to view and control interconnection facilities in order to intermittently interrupt discharge and charging due to system conditions and related outages, which would likely require upfront and ongoing costs for both Idaho Power and interconnection customers. Idaho Power requests that the Commission consider including additional language to ensure that the transmission provider can disconnect, or

[2767] Clean Energy Associations Initial Comments at 52.

[2768] Clean Energy Associations Reply Comments at 10.

[2769] SEIA Reply Comments at 26-27 (citing IREC Initial Comments, app. A at 43-48, 56, 159).

[2770] Idaho Power Initial Comments at 15-16.

take other action, including seeking damages, in the event that the charging electric storage resource does not follow its schedule.

1468. Eversource states that it is essential for system operators and transmission planners to have sufficient visibility and controls in place to ensure that the transmission system is not placed in unstudied and potentially insecure N-1 contingency states.[2771] Eversource suggests that this issue, as well as other issues of grid dispatch, should be the subject of its own proceeding. Alternatively, Eversource requests that the Commission require that interconnection customers with proposed operational study assumptions have technological controls in place that automatically limit the electric storage facility's operation to the proposed operational parameters. Eversource further requests that the Commission reflect these requirements in the body of the *pro forma* LGIA, and not only the appendices.

1469. NARUC and Public Interest Organizations support the proposed requirement to consider resources to be in breach of their LGIA if they fail to operate as intended.[2772] NARUC asserts that such a consequence, in combination with technology and software that can limit the operations of an electric storage resource, should sufficiently mitigate behavior that deviates from planned.[2773] Public Interest Organizations contend that

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[2771] Eversource Initial Comments at 35-36.

[2772] NARUC Initial Comments at 37; Public Interest Organizations Initial Comments at 48-50.

[2773] NARUC Initial Comments at 37-38.

installing control technologies would allow the transmission provider and interconnection customer to engage in an interactive dialogue to develop a set of operating assumptions that both satisfy the interconnection customer's operational desires and align with "good utility practice."[2774]

1470. rPlus generally supports the proposal but argues that the proposed termination requirements for the interconnection customer should the operational characteristics not be met are too stringent and restrictive.[2775] rPlus agrees that it is important to memorialize the studied operational assumptions in the interconnection agreement but asserts that it would benefit from the inclusion of additional language should deviation from the originally defined operational assumptions be beneficial. Therefore, rPlus suggests that the Commission remove any explicit or implied requirement for electric storage resources not to charge during peak load periods and add language to retain the possibility of altering the operational characteristics when these changes would benefit the reliable and efficient operation of the transmission system or benefit ratepayers.

1471. Invenergy supports the proposed reform to accommodate study assumptions that more reasonably approximate anticipated actual operations, but opposes requiring the studied operating conditions to be memorialized in the interconnection agreement.[2776] Invenergy states that, if there are concerns that an unexpected event may require a facility

[2774] Public Interest Organizations Initial Comments at 48.

[2775] rPlus Initial Comments at 6.

[2776] Invenergy Initial Comments at 59-61.

to occasionally operate outside those conditions, those concerns should be addressed through the regional transmission planning process, rather than forcing interconnection customers to fund upgrades that are rarely if ever needed.[2777]

1472. Several commenters suggest modifications to the proposal to better achieve the Commission's goal. For example, Pine Gate suggests that the Commission require transmission providers to use a uniform set of minimum interconnection study requirements (e.g., by eliminating the use of extreme contingency scenarios and overly conservative operational characteristics and strategies) to facilitate effective, efficient interconnection queue processing, which is an essential prerequisite of consumer protection.[2778] With respect to the provision of ancillary services, Pine Gate requests that the interconnection customer not be required to definitively indicate the specific ancillary services that it would or would not provide in the initial interconnection request because it is not possible for the interconnection customer to know with certainty which ancillary services it may be eligible to provide when it is ultimately placed in service.[2779] For this reason, Pine Gate requests that the Commission require the interconnection customer to list in the original interconnection request only whether it intends to provide ancillary services generally.[2780]

[2777] *Id.* at 61-62.

[2778] Pine Gate Initial Comments at 55.

[2779] *Id.* at 52.

[2780] *Id.* at 53.

1473. Union of Concerned Scientists urges the Commission to direct in the final rule that technical capabilities offered by an interconnection customer be appropriately recognized and used in the modeling of transmission impacts and their mitigation, including the ability to respond to contingencies and provide dynamic real or reactive power, which if omitted could lead to millions of dollars of costs to customers to provide such capability by other means.[2781]

1474. Interwest supports allowing interconnection customers to request that transmission providers apply certain study assumptions to better approximate realistic operations and requiring transmission providers to apply congestion management practices to unusual events, developed through regional transmission planning processes, rather than building in assumptions assuming worst-case operations scenarios.[2782]

1475. Public Interest Organizations recommend that, if a transmission provider finds an interconnection customer's proposed operating assumptions to be in conflict with "good utility practice," the transmission provider should be required to provide the interconnection customer with a clear explanation of why the submitted operating assumptions are insufficient or inappropriate, and allow the interconnection customer to revise and resubmit the proposed operating assumptions as necessary, within a reasonable time period.[2783]

[2781] Union of Concerned Scientists Reply Comments at 13-14.

[2782] Interwest Reply Comments at 15.

[2783] Public Interest Organizations Initial Comments at 47-48, 49.

1476. Clean Energy Associations urge the Commission to define study parameters such as "peak load" and "net peak load."[2784] Clean Energy Associations request that the Commission define "net peak load" as the period during which transmission providers must not study a facility as withdrawing energy. Clean Energy Associations note that in regions with high solar penetration, the net peak load hour diverges from the peak load hour and migrates to later in the day and, under these conditions, low prices during the peak load hour may create incentives for storage to charge, whereas prices would be high during the net peak load hour creating incentives to discharge. Therefore, Clean Energy Associations contend that using the net peak load as the period of study will ensure that studies continue to accurately reflect expected economic price response of storage as system conditions evolve.

1477. NextEra and Clean Energy Associations urge the Commission to require transmission providers to use additional study assumptions beyond just whether electric storage and co-located resources (including hybrid resources) should charge during peak load periods. Both NextEra and Clean Energy Associations argue that transmission providers should not study electric storage resources as injecting energy during low load and shoulder periods because that does not reasonably reflect the rational economic behavior and typical operations of such resources.[2785]

[2784] Clean Energy Associations Initial Comments at 53-54.

[2785] NextEra Initial Comments at 37; Clean Energy Associations Initial Comments at 53.

1478. In contrast, MISO argues against requiring additional study assumptions for electric storage resources.[2786] MISO notes that there may be times in the future when renewable resources are constrained or unavailable due to the lack of fuel (e.g., no wind or sun) such that the MISO transmission system will need to call upon electric storage resources for injection: but, if these resources are not permitted to discharge due to their operational assumptions, then the transmission system's reliance on those resources could lead to reliability risks.

1479. Several other commenters urge the Commission not to define study parameters, such as "peak load" or "net peak load," and instead allow for regional flexibility.[2787] For example, rather than define peak load, Microgrid Resources states that the Commission should require individual evaluation of the expected operating assumptions for the resource(s) being studied.[2788] Enel asserts that it does not believe clear and transparent criteria regarding the peak load period could be developed such that the limitations on a generating facility could appropriately be modeled with only a few power flow model "snapshots in time" serving as the basis for the restriction.[2789]

[2786] MISO Initial Comments at 116.

[2787] Ameren Initial Comments at 29; Enel Initial Comments at 74; Idaho Power Initial Comments at 16; Microgrid Resources Initial Comments at 8; Shell Initial Comments, app. A at iii.

[2788] Microgrid Resources Initial Comments at 8.

[2789] Enel Initial Comments at 74.

1480. Several commenters support eliminating unrealistic interconnection study assumptions for resource types other than electric storage resources, such as assuming that a solar facility will operate a night, or that a wind resource will produce maximum output during low-wind seasons.[2790] Ameren, Cypress Creek, Microgrid Resources, NARUC, Pine Gate, and rPlus all request that the Commission extend this reform to allow any resource type, not just electric storage or co-located resources, to request that interconnection studies be based on their particular operating assumptions and characteristics.[2791] NARUC further asserts that it is reasonable to allow interconnection customers to request that transmission providers not study interconnecting generating facilities in ways that are not physically possible, subject to the same proposed requirement that the generating facility be equipped with sufficient control technologies and penalties for deviations.[2792] Microgrid Resources urges the Commission to define microgrid in the tariff, noting particularly the inclusion of load, and to make clear that

[2790] *Id.*; AES Clean Energy Initial Comments at 24-25; Ameren Initial Comments at 29; CREA and NewSun Initial Comments at 92; Cypress Creek Initial Comments at 9-10; Invenergy Initial Comments at 59-61; Microgrid Resources Initial Comments at 7-8; Pine Gate Initial Comments at 54; Public Interest Organizations Initial Comments at 48-49; R Street Initial Comments at 16; rPlus Initial Comments at 6.

[2791] Ameren Initial Comments at 29; Cypress Creek Initial Comments at 9-10; Microgrid Resources Initial Comments at 7; NARUC Initial Comments at 38; Pine Gate Initial Comments at 54; rPlus Initial Comments at 6.

[2792] NARUC Initial Comments at 38.

interconnection studies must be based on operating assumptions for the microgrid as a whole.[2793]

1481. Pattern Energy asserts that transmission providers should be required to update their operating assumptions annually, after stakeholder input.[2794] Pattern Energy asserts that some transmission providers require light-load reliability analysis for wind resources but not for natural gas plants, which is unduly discriminatory.[2795]

1482. Some commenters support expanding the proposed reforms to the entire facility of hybrid or co-located resources. For instance, ENGIE recommends that interconnection customers submitting hybrid or co-located resources should be able to specify operating parameters across the entire generating facility, including variable energy resources, within their interconnection request to allow interconnection customers to reflect parameters such as solar-based charging of the electric storage resource more accurately.[2796] Pine Gate states that co-located resources are typically studied independently, which requires studying the combined maximum injection of the two generating facilities that are co-located, despite the fact that studying in this manner overestimates the impact on the transmission system and could trigger unnecessary

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[2793] Microgrid Resources Initial Comments at 7.

[2794] Pattern Energy Initial Comments at 13.

[2795] *Id.* (referencing PJM Manual 14B at 47, section 2.3.1.1).

[2796] ENGIE Initial Comments at 11.

network upgrades.[2797] Pine Gate asserts that, consistent with the NOPR's proposals regarding operating assumptions for electric storage resources and co-located resources, the Commission should permit an interconnection customer to specify the proposed operation of all components of a co-located resource in its interconnection request. SEIA contends that studying two, co-located resources as a single resource would be more accurate, as this would reflect the actual electrical impact to the transmission system.[2798]

1483. Although not entirely opposed to the proposed reform, PacifiCorp asserts that this proposed reform should not be extended to co-located and hybrid resources because monitoring and enforcing operational limitations could be complex, and incorporating operational limitations could complicate the cluster study process.[2799] Nevertheless, PacifiCorp encourages the Commission to permit transmission providers to opt-in to extending this type of reform to hybrid resources if appropriate for their systems.

1484. Several other commenters urge the Commission to go further and require transmission providers to use more realistic operating assumptions without requiring the interconnection customer to request that transmission provider do so.[2800] Public Interest Organizations argue that extending the reforms to all generation technologies would help

[2797] Pine Gate Initial Comments at 45.

[2798] SEIA Initial Comments at 38.

[2799] PacifiCorp Initial Comments at 41-42.

[2800] AES Clean Energy Initial Comments at 24-25; CREA and NewSun Initial Comments at 92; R Street Initial Comments at 16.

prevent unduly discriminatory treatment.[2801] Therefore, Public Interest Organizations recommend that the Commission require transmission providers to work with interconnection customers to ensure operating assumptions reflect physical, operational, and market realities, "good utility practice," and applicable reliability standards. AES Clean Energy argues that the Commission should require transmission providers to establish a process to revisit and update operating assumptions of different resource types in consultation with stakeholders to ensure that these operating assumptions are realistic and approximately reflect the expected actual operation of these resources.[2802]

1485. Shell supports the use of accurate modeling assumptions, including for variable energy resources, but argues that electric storage and renewable resources should not be treated in the same way because electric storage is dispatchable and renewable resources generally are not dispatchable.[2803] Further, Shell asserts that the Commission should not assume all wind and solar resources are the same (and not dispatchable).

1486. AECI and NextEra oppose extending the proposed reform to other resources types.[2804] NextEra opposes extending customized operating assumptions to wind and solar energy resources because doing so could unduly complicate subsequent operational decisions for the system operator and possibly restrict the system operator's ability to call

[2801] Public Interest Organizations Initial Comments at 49.

[2802] AES Clean Energy Initial Comments at 24-25.

[2803] Shell Initial Comments, app. A at iii.

[2804] AECI Initial Comments at 8; NextEra Initial Comments at 37.

on resources when needed.[2805] AECI proposes to continue studying wind and solar resources as NRIS facilities that are dispatched at 100% to avoid potential reliability issues at the worst times.[2806] MISO explains that it currently requires interconnection customers to be responsible for limiting and controlling their own dispatch in some conditions, but that it has no ability to monitor in real time if an interconnection customer violates its operating limits.[2807] MISO states that it is unaware of any plant side control device or operational tool that MISO could use to prevent a generating facility's injection to enforce an electric storage resource's operating assumptions regarding discharging. Idaho Power states that it is unclear how a cluster study with multiple interconnection requests could be performed when accounting for numerous and potentially conflicting study parameters, such as "low wind season" for one interconnection customer but not for another.[2808] Idaho Power seeks clarification of the definition of study parameters such as "low wind season."

1487. Some commenters support the Commission defining the terms firm and non-firm charging service for electric storage resources and requiring transmission providers to define study criteria to interconnect related to both firm and non-firm charging.[2809] For

[2805] NextEra Initial Comments at 37.

[2806] AECI Initial Comments at 8.

[2807] MISO Initial Comments at 116.

[2808] Idaho Power Initial Comments at 16.

[2809] CESA Initial Comments at 12-13; Clean Energy Associations Initial

example, Clean Energy Associations support enabling interconnection customers with electric storage resources and hybrid resources to request non-firm transmission service for their charging energy, provided that transmission providers update study criteria and interconnection processes for such service accordingly and provide definitions of firm and non-firm charging service for electric storage resources.[2810] CESA argues that electric storage resources should not be forced to use one type of charging service over another since some resources may find it sufficient to take advantage of charging capacity as it is available whereas others may want or need greater assurances of charging capacity and are willing to pay for the requisite network upgrades.[2811] CESA urges the Commission to set requirements as to how partial or full firm charging services should be offered on a flexible, as-requested basis, such that an interconnection customer can seek firm charging service for specific time windows or for a portion of the electric storage resource's nameplate or interconnection capacity. CESA asserts that, as discussed in the NOPR, accommodating firm and as-available charging service options should reflect the operating capabilities of the storage resource (i.e., price responsive, dispatchable), achieve efficient market outcomes, and avoid expensive and unnecessary upgrades."[2812]

Comments at 54-56; ENGIE Initial Comments at 12.

[2810] Clean Energy Associations Initial Comments at 54.

[2811] CESA Initial Comments at 12-13.

[2812] *Id.* at 12.

1488. Clean Energy Associations assert that the Commission should direct transmission providers to use the following criteria for studying interconnection requests that opt for non-firm charging service: (1) the electric storage resource should have the option to receive electric energy using the existing firm or non-firm capacity of the transmission system on an "as available" basis; (2) any study of an electric storage resource charging should allow the interconnection customer to elect to use a lower charging level or a control technology to mitigate any identified constraints in lieu of being assigned network upgrades to address such constraints; and (3) the electric storage resource should receive information relative to any network upgrades, charging restrictions, or control requirements in advance of signing an interconnection agreement.[2813] Clean Energy Associations urge the Commission to direct transmission owners to indicate conditions under which charging energy could be curtailed in interconnection agreements that include non-firm service for charging energy. Clean Energy Associations also caution that the Commission should avoid recategorizing charging energy of electric storage resources as a wholesale load, which would be contrary to the Commission's findings in Order No. 841.

1489. AEP suggests that clarifications would be needed for the proposed definitions of firm and non-firm charging to be effective. For example, AEP asserts that the proposed definitions for firm and non-firm charging service conflate different products and

[2813] Clean Energy Associations Initial Comments at 55-56.

services required to charge an electric storage resource.[2814] AEP argues that charging service is not a form of interconnection service, nor is interconnection service referred to in the industry as firm or non-firm. According to AEP, it is the delivery service (i.e., transmission and wholesale distribution service) that can be firm or non-firm and therefore the relevant question is whether, in the interconnection process, an electric storage resource can or needs to request to be studied as a "firm" or "non-firm" load for delivery purposes. AEP asserts that the Commission should recognize that, for electric storage resources, the interconnection cluster study process should include an analysis of transmission service. AEP notes that the Commission has permitted the California utilities to study the need for wholesale distribution upgrades required for charging on a firm basis as part of the interconnection study process. AEP argues that, if it is technically possible to distinguish loads, a load that affects human safety, health, and welfare directly should have priority over the charging of an electric storage resource, unless for example, if the electric storage resource will be used for blackstart after an outage, adding that the final rule does not need to interfere with emergency load shedding protocols.

1490. Shell asserts that the need for firm or non-firm transmission service will vary by generating facility, as well as by the usage pattern of the electric storage resource (e.g., whether the electric storage resource is standalone or part of a hybrid resource that is AC-

[2814] AEP Initial Comments at 48-50.

coupled, DC-coupled, or DC-tight-coupled).[2815] Shell states that, if an electric storage resource is charging from the transmission system as non-firm load, and the resource owner is required to comply with the transmission provider's real-time dispatch orders to cease charging from the transmission system due to reliability concerns, then there is no need for long-term firm transmission service reservations to serve the electric storage resource. Shell contends that non-firm electric storage load should not be required to acquire transmission service prior to charging from the transmission system, as such charging will be captured by the revenue meter and can be billed at the transmission provider's non-firm point-to-point transmission rate at the end of the billing period.

1491. Xcel suggests that the evaluation of non-firm charging must assume a price and then the electric storage resource should be bound to that price.[2816] Xcel contends that, if an electric storage resource is studied as non-firm load but ends up offering to buy energy in the market above average market prices, the study will not represent the resulting dispatch. Therefore, Xcel recommends that electric storage resources and other non-firm load should be required to have a maximum bid price that is included in Attachment C of the *pro forma* LGIA.

1492. Some commenters oppose the Commission defining firm and non-firm charging or requiring transmission providers to define study criteria as part of this rulemaking.[2817]

[2815] Shell Initial Comments, app. A at iii.

[2816] Xcel Initial Comments at 46.

[2817] Ameren Initial Comments at 29; Idaho Power Initial Comments at 16; PPL

For example, PPL asserts that the Commission should leave defining such study parameters to the transmission providers.[2818]

1493. Several commenters suggest clarifications to the proposed reform regarding the timing of submitting operating assumptions.[2819] Clean Energy Associations and ENGIE recommend that the Commission define a clear decision point in the interconnection study process before which interconnection customers may adjust operating assumptions and after which inputs remain constant.[2820] APS suggests that the Commission modify the proposal to specify that any changes to the operating assumptions initially provided by the interconnection customer would be considered a material modification.[2821]

(d) <u>Alternative Proposals and Requests for Further Process</u>

1494. Enel argues that using power flow studies and assuming extreme transmission system conditions matches the concept of a firmer product well (e.g., for NRIS or transmission service studies), but applied to ERIS studies it implies that an ERIS resource cannot or will not curtail, absorb congestion costs, or be redispatched to mitigate

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Initial Comments at 23.

[2818] PPL Initial Comments at 23.

[2819] AES Clean Energy Initial Comments at 24; APS Initial Comments at 22; Clean Energy Associations Initial Comments at 56-57; ENGIE Initial Comments at 11.

[2820] Clean Energy Associations Initial Comments at 56-57; ENGIE Initial Comments at 11.

[2821] APS Initial Comments at 22.

transmission system disturbances, which goes beyond "as available" service and does not allow for lower-cost mitigation options.[2822] For these reasons, Enel recommends that the Commission direct transmission providers to replace power flow studies with Security Constrained Economic Dispatch analysis for ERIS service studies instead of the Commission's proposed reform,[2823] or in the alternative, require appropriately supported fuel-based dispatch assumptions in ERIS and, where appropriate, NRIS study models.[2824]

1495. Several other commenters support requiring transmission providers to apply realistic fuel-based dispatch assumptions to all resource types.[2825] Additionally, Invenergy notes that both MISO and SPP already use realistic fuel-based dispatch assumptions in their interconnection study processes.[2826] Although MISO believes that a fuel-based dispatch methodology would address the concerns stated in the NOPR about unrealistic operating assumptions, MISO also believes that study methods should be flexible to the unique needs of a region's stakeholders and that the Commission should allow flexibility regarding how a transmission provider conducts its studies.[2827] MISO

[2822] Enel Initial Comments at 75.

[2823] *Id.* at 73, 75.

[2824] *Id.* at 77-78.

[2825] Enel Initial Comments at 77-78; Interwest Reply Comment at 15; Invenergy Initial Comments at 60-61.

[2826] Invenergy Initial Comments at 60-61.

[2827] MISO Initial Comments at 119.

asserts that fuel-based dispatch enables more efficient generator interconnection because it recognizes that not all generating facilities will be dispatched up to their requested interconnection service at all times of the year and that some fuels will not be dispatched when other fuels are being dispatched.[2828] MISO explains that its current fuel dispatch method also addresses withdrawal for electric storage resources and was informed by operational data.[2829]

1496. Public Interest Organizations encourage the Commission to consider a requirement that would ensure operational and market realities are appropriately reflected in operating assumptions for the purposes of interconnection studies.[2830] Public Interest Organizations state that this could include both operational practices and procedures as well as market-based price signals for curtailment and congestion management. Furthermore, Public Interest Organizations contend that fossil generating facilities should not be expected to generate at or near peak output during times when market prices are depressed, such as during periods of high renewable generation.[2831]

1497. IREC asserts that interconnection application forms for small generating facilities should be updated to include information about electric storage resources and, where

[2828] *Id.* at 117, 119.

[2829] *Id.* at 117-118 (citing MISO, Business Practice Manual-15, tbl. 6-1).

[2830] Public Interest Organizations Initial Comments at 48.

[2831] *Id.* at 48-49 (citing Joe Daniel & Sam Gomberg, Union of Concerned Scientists, *Why Does Wind Energy Get Wasted?* (Nov. 16, 2021), https://www.ucsusa.org/resources/wind-oversupply-myths).

export controls are used, the type of export control and the equipment type and settings that will be used.[2832] IREC asserts that, in order for the interconnection process to fully recognize the ways electric storage resources can be designed and controlled to avoid transmission system constraints, utilities should consider operating profiles (which can include operating schedules) in their feasibility studies and system impact studies.[2833]

1498. Several commenters urge the Commission to hold a technical conference and/or open a new proceeding to sort out the complex details of this proposed reform.[2834] For example, Clean Energy Associations note that the Commission could build a further evidentiary record regarding parameters for evaluating electric storage and other resources via a technical conference, with the aim of developing reasonable and consistent assumptions across regions.[2835] SEIA urges the Commission to convene a technical conference in this proceeding to increase transmission provider certainty and confidence in the capabilities and testing of power control systems.[2836] ISO-NE suggests that its concerns with the proposed reform may be better addressed through the

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[2832] IREC Initial Comments at 15, attach. A.

[2833] *Id.* at 16, attach. A.

[2834] Clean Energy Associations Initial Comments at 53; Eversource Initial Comments at 35; ISO-NE Initial Comments at 40; Puget Sound Initial Comments at 13.

[2835] Clean Energy Associations Initial Comments at 53.

[2836] SEIA Initial Comments at 27.

establishment of a new category of interconnection service for the charging mode of electric storage devices as part of a separate proceeding.[2837]

(e) <u>Comments Regarding Transmission Service Request Studies</u>

1499. Clean Energy Associations note that some RTOs/ISOs determine the network upgrades needed to accommodate the charging of electric storage resources as part of the interconnection process, whereas other transmission providers do so in the transmission service request process.[2838] Similarly, Xcel states that charging from the transmission system can be evaluated and approved through the designation of a new delivery point as part of a transmission service request.[2839] Xcel further notes that it is unaware of a transmission service study process defined in the *pro forma* tariff that specifically evaluates non-firm load. Puget Sound states that it currently studies charging outside of the interconnection process and recognizes that charging could be considered a retail or a transmission product once the load piece is interconnected.[2840] However, Puget Sound asserts that charging should be studied in the interconnection process, and the transmission provider should be granted more time to study this additional element.

[2837] ISO-NE Initial Comments at 40.

[2838] Clean Energy Associations Initial Comments at 54-55 (referencing, e.g., ISO-NE Planning Procedure No. 5-6, at 18 (2022); MISO, Business Practice Manual 15-r24, at 53.

[2839] Xcel Initial Comments at 46-47.

[2840] Puget Sound Initial Comments at 11-12.

Puget Sound seeks clarity as to whether the proposed reform means that charging should now be considered part of the interconnection process, or if it can be part of the process should the transmission provider wish to include it. Further, Puget Sound argues that the Commission should standardize the *pro forma* LGIA to include specific operating assumptions to avoid interconnection request delays due to needing to file a non-conforming LGIA with the Commission and/or interconnection customer hesitancy.

1500. In contrast, Tri-State argues that it is inappropriate to study charging of electric storage resources within a generator interconnection study, and instead asserts that this type of analysis is best performed as a part of a transmission service study, which covers delivery of energy to load or charging of an electric storage resource.[2841] Similarly, SPP argues that evaluating the impact of an electric storage resource's charging on the transmission system is better suited to other existing processes designed to assess load impact, such as the long-term transmission service study process, the short-term transmission service evaluation process, or market processes.[2842]

(f) <u>Requests for Clarification and Flexibility</u>

1501. Pine Gate requests that the Commission provide additional guidance regarding how transmission owners should perform studies and what network upgrade costs will be allocated to interconnection customers as a result.[2843] Pine Gate states that transmission

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[2841] Tri-State Initial Comments at 22.

[2842] SPP Initial Comments at 25.

[2843] Pine Gate Initial Comments at 52.

providers may need to study electric storage or co-located resources based on worst-case operating assumptions to understand the potential impact these resources would have on the transmission system absent operating restrictions being implemented. However, Pine Gate requests that the Commission clarify that network upgrade costs will not be assigned to the interconnection customer based on the unrealistic worst-case scenarios where there is agreement to implement operating restrictions.

1502. Elevate requests that the Commission clarify that the proposed reform applies to all study processes related to the interconnection of electric storage resources, including generator replacement, surplus interconnection, and requests to modify an existing generation resource, arguing that there is no reason for the Commission to require that transmission providers use realistic study parameters only in the context of requests for new interconnection service while allowing unrealistic study assumptions in other study processes.[2844]

1503. CAISO is concerned that, if not modified, the proposed reform would require transmission providers to provide firm charging options, whereas CAISO asserts that it does not currently provide firm charging service and stakeholders have never requested such service.[2845] CAISO argues that requiring firm charging service would have a profound impact on organized electricity markets and asserts that if the Commission proposes to allow electric storage resources to bypass economic dispatch and charge

[2844] Elevate Initial Comments at 13-14.

[2845] CAISO Initial Comments at 34-35.

whenever they desire—even during stressed peak conditions—it should do so expressly and not in the context of a rulemaking addressing interconnection. CAISO asserts that the Commission should consider a simple clarification and avoid requiring transmission providers to offer firm charging, but instead require transmission providers that offer firm charging to allow interconnection customers to request it at the outset of their interconnection request.

1504. Environmental Defense Fund urges the Commission to clarify that an apparent failure to operate in accordance with agreed-upon conditions should be treated as a normal alleged default or breach as governed by article 17 of the *pro forma* LGIA, which would not result in immediate termination.[2846] Environmental Defense Fund asserts that the requirements of article 17.1 of the *pro forma* LGIA state that a breaching party be given an opportunity to cure the breach and that termination is only available if the breaching party fails to cure or the breach is not capable of being cured. Similarly, Hydropower Commenters generally support the proposal, but believe that the proposed requirement that if an interconnection customer fails to operate its electric storage resource in accordance with the operating assumptions memorialized in the interconnection agreement, the interconnection customer may be considered in breach and the transmission provider may pursue termination of the interconnection agreement, is overly restrictive, will discourage the development of pumped storage projects, and

[2846] Environmental Defense Fund Initial Comments at 6-7.

should be modified.[2847] Instead, Hydropower Commenters urge the Commission to provide for a standard cure period to address deviations, and penalties in the event of failure to cure.

1505. MISO states that the proposed reform is unclear because the text of the NOPR states that the Commission intends operating instructions to only apply to an electric storage resource's ability to describe how it will withdraw energy from the transmission system (i.e., charge a battery), whereas the proposed *pro forma* LGIP revisions state that the operating assumptions can also apply to the manner the interconnection request states that the electric storage resource will discharge.[2848] MISO asks that the Commission clarify that the text of the NOPR is correct, and that the Commission did not intend to propose to allow electric storage resources to define the operating assumptions for how they will inject into the transmission system because, according to MISO, allowing interconnection requests to define operating assumptions regarding discharge would result in operational problems and would be discriminatory to other generating facilities.

1506. Hydropower Commenters suggest that the proposed reform be modified to include a simplified procedure for amending an interconnection customer's interconnection agreement to optimize the operating parameters of a pumped storage plant to the extent the transmission system is available.[2849]

[2847] Hydropower Commenters Initial Comments at 23-24.

[2848] MISO Initial Comments at 115.

[2849] Hydropower Commenters Initial Comments at 24.

1507. Some commenters note that several transmission providers already study electric storage resources using more realistic operating assumptions and assert that transmission providers should have the flexibility to determine the assumptions used when studying generating facilities interconnecting to the transmission system, including operating assumptions for electric storage resources, while also factoring in input from the interconnection customer.[2850] NESCOE argues that the final rule should require transmission providers to work with the relevant states, transmission owners, electric storage resource interconnection customers, and stakeholders in their region to develop modeling assumptions for electric storage resources that are reasonable, realistic, and ensure the ability to interconnect is offered on a non-discriminatory basis.[2851]

1508. National Grid recommends that the Commission provide regional flexibility to adopt or decline this proposed reform after transmission providers receive input from their stakeholders to determine if ad hoc proposed operating assumptions for interconnection requests are reasonable and appropriate or if certain pre-determined acceptable ranges of assumptions are consistent with reliability.[2852] APPA-LPPC argues that the proposal could entail creating entirely new models for off-peak scenarios, not just running sensitivity analyses from an existing model, and therefore urges the Commission

[2850] APPA-LPPC Initial Comments at 29-30; Bonneville Initial Comments at 23; MISO Initial Comments at 117; National Grid Initial Comments at 41; NESCOE Reply Comments at 19.

[2851] NESCOE Reply Comments at 18.

[2852] National Grid Initial Comments at 41.

to give transmission providers the autonomy to determine whether additional transmission studies are needed.[2853]

iii. Commission Determination

1509. We adopt the NOPR proposal, subject to modification, to revise sections 3.1.2, 3.2.1.2, 3.2.2.2, 3.3.1, 3.4.2, 4.4.3, 7.3, 8.2, and Appendix 1 of the *pro forma* LGIP and article 17.2 and Appendix H of the *pro forma* LGIA to require transmission providers, at the request of the interconnection customer, to use operating assumptions in interconnection studies that reflect the proposed charging behavior of electric storage resources[2854] (whether standalone, co-located generating facilities,[2855] or part of a hybrid generating facility[2856])—i.e., whether the interconnecting generating facility will or will not charge during peak load conditions—unless good utility practice, including applicable reliability standards,[2857] otherwise requires the use of different operating

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[2853] APPA-LPPC Initial Comments at 29-30.

[2854] An electric storage resource is a generating facility capable of receiving electric energy from the grid and storing it for later injection of electricity.

[2855] As noted above, co-located generating facilities are more than one generating facility that are located on the same site and that are connected at the same point of interconnection that are operated and dispatched as separate generating facilities. *See supra* Section III.C.1.a.iii.

[2856] As noted above, a hybrid generating facility is a generating facility composed of more than one device of different technology types for the production and/or storage for later injection of electricity that are located on the same site and are operated and dispatched as a single integrated generating facility. *See supra* Section III.A.6.b.iii.

[2857] Applicable reliability standards means “the requirements and guidelines of the Electric Reliability Organization and the Balancing Authority Area of the Transmission System to which the Generating Facility is directly interconnected.” *See pro forma* LGIP

assumptions.[2858] We clarify that studying electric storage resources, at the request of the interconnection customer, according to their planned operating assumptions means only the operating assumptions for withdrawals of energy (e.g., the charging of an electric storage resource) in interconnection studies.

1510. We find that by more accurately reflecting the technical capabilities of electric storage resources in interconnection studies through the use of appropriate operating assumptions, this reform ensures the reliable interconnection of new electric storage resources without overestimating their impact on the transmission system, thereby ensuring just and reasonable rates by avoiding excessive and unnecessary network upgrades that may hinder the timely development of new generating facilities that stifles competition in the wholesale market. We also find that reflecting the technical capabilities of electric storage resources through the use of appropriate operating assumptions in interconnection studies reduces unduly discriminatory or preferential barriers to the interconnection of electric storage resources.

1511. We adopt the proposed revisions, subject to modification, to section 3.1.2 of the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use operating assumptions that reflect the proposed charging behavior of an

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section 1 (Definitions).

[2858] For clarity, we note that the reforms described in this determination section and the related sections of the *pro forma* LGIP apply to all interconnecting electric storage resources, whether they are standalone, co-located generating facilities, or part of a hybrid generating facility.

electric storage resource, allow interconnection customers to resubmit their operating assumptions if the transmission provider finds the originally proposed operating assumptions are in conflict with good utility practice, and allow the transmission provider to require the interconnection customer to install additional control technologies. We agree with Public Interest Organizations that transparency is necessary when a transmission provider finds that an interconnection customer's operating assumptions conflict with good utility practice.[2859] Therefore, we modify the proposed revisions to section 3.1.2 of the *pro forma* LGIP to require that, if a transmission provider finds an interconnection customer's proposed operating assumptions to be in conflict with good utility practice, the transmission provider must provide the interconnection customer with a clear explanation in writing of why the submitted operating assumptions are insufficient or inappropriate by no later than 30 calendar days before the end of the customer engagement window and allow the interconnection customer to revise and resubmit the proposed operating assumptions one time at least 10 calendar days before the end of the customer engagement window.

1512. We adopt the proposed revisions to section 3.2.1.2 of the *pro forma* LGIP to require transmission providers to study electric storage resources that request ERIS service according to the interconnection customer's proposed operating assumptions. We adopt the proposed revisions to section 3.2.2.2 of the *pro forma* LGIP to require

[2859] Public Interest Organizations Initial Comments at 47-49.

transmission providers to study electric storage resources that request NRIS service according to the interconnection customer's proposed operating assumptions.

1513. We agree with Elevate and clarify that the reform to use operating assumptions in interconnection studies, at the request of the interconnection customer, that reflect the proposed charging behavior of an electric storage resource applies to the operating assumptions used in all study processes related to the interconnection of electric storage resources. Accordingly, we modify the NOPR proposal to require transmission providers, at the request of the interconnection customer, to use operating assumptions that reflect the proposed charging behavior of an electric storage resource in additional study processes, as described below.

1514. With respect to surplus interconnection service, we modify the NOPR proposal to revise section 3.3.1 of the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use operating assumptions that reflect the proposed charging behavior of an electric storage resource in the surplus interconnection service process.

1515. We adopt the proposed revisions to section 3.4.2 of the *pro forma* LGIP to require interconnection customers to include in their interconnection request the proposed operating assumptions that reflect the proposed charging behavior of the electric storage resource and a description of any control technologies that will limit the operation of the electric storage resource to its intended operation.

1516. To the extent an interconnection customer requests to modify a generating facility already in the interconnection queue by adding an electric storage resource to the

interconnection request, the transmission provider shall study such a modification in accordance with section 4.4.3 of the *pro forma* LGIP using operating assumptions that reflect the proposed charging behavior of an electric storage resource, at the request of the interconnection customer. Accordingly, we modify the NOPR proposal to revise section 4.4.3 of the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use operating assumptions that reflect the proposed charging behavior of an electric storage resource in the material modification process.

1517. We adopt the proposed revisions to section 7.3 of the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use operating assumptions that reflect the proposed charging behavior of an electric storage resource in the cluster study process and to allow, but not require, transmission providers to: (1) memorialize the generating facility's operating assumptions in Appendix H of the interconnection customer's LGIA; and/or (2) require control technologies (software and/or hardware) for an electric storage resource that wishes to limit its operations during peak load conditions, with such protection devices included in Appendix C of the interconnection customer's LGIA.

1518. We adopt the proposed revisions to section 8.2 of the *pro forma* LGIP to require transmission providers, at the request of the interconnection customer, to use operating assumptions that reflect the proposed charging behavior of an electric storage resource in the interconnection facilities study process.

1519. We adopt the NOPR proposal to revise Appendix 1 of the *pro forma* LGIP to require interconnection customers to provide to the transmission provider as part of the

initial interconnection request: (1) the requested operating assumptions for the interconnecting electric storage resource; and (2) a description of any applicable control technologies. However, we agree with MISO and Pine Gate that it is not necessary, and may not be possible, to specify the specific ancillary services that an electric storage resource will provide before entering the interconnection queue, particularly because the market rules addressing the provision of ancillary services from electric storage resources, whether they are standalone, part of co-located generating facilities, or part of a hybrid generating facility, are still being developed in multiple markets and such rules will likely change over the coming years.[2860] Therefore, we decline to adopt the proposed revision to require interconnection customers to list the specific ancillary services they intend to provide as part of the initial interconnection request.[2861] In addition, we agree with MISO and CAISO that control technologies frequently evolve, and interconnection customers that choose to specify operating assumptions should be responsible for including appropriate control technologies with their requests to use such operating assumptions. Therefore, we also decline to adopt the proposed revision to require transmission providers to publicly post a list of acceptable control technologies.

1520. We adopt the NOPR proposal to revise Appendix 1 of the *pro forma* LGIP to require interconnection customers to provide to the transmission provider any proposed operating assumptions for the interconnecting electric storage resource as part of the

[2860] MISO Initial Comments at 118; Pine Gate Initial Comments at 52.

[2861] NOPR, 179 FERC ¶ 61,194 at P 281.

initial interconnection request. This timing ensures that the flexibility provided by this reform does not delay the cluster study process by ensuring the transmission provider has all necessary information at the time interconnection studies commence. In response to commenters that request that the Commission define a clear decision point after which changes to operating assumptions may be considered a material modification,[2862] we reiterate that the operating assumptions must be submitted as part of the initial interconnection request. Further, we clarify that such operating assumptions only pertain to the proposed charging behavior of an electric storage resource, i.e., whether the interconnecting resource will or will not charge during peak load conditions.

1521. We modify the NOPR proposal to add article 17.2 to the *pro forma* LGIA to describe a violation of operating assumptions for generating facilities, including for an electric storage resource. We also add Appendix H to the *pro forma* LGIA as the location for the interconnection customer to memorialize its operating assumptions. If the owner of the generating facility fails to operate the generating facility in accordance with its operating assumptions, as memorialized in Appendix H of the *pro forma* LGIA, the transmission provider may pursue termination of the LGIA through the breach and cure provisions found in article 17 of the *pro forma* LGIA. As already provided for in article 17 of the *pro forma* LGIA, we agree with Environmental Defense Fund that interconnection customers should be given the opportunity to cure a breach of the LGIA

[2862] AES Clean Energy Initial Comments at 24; APS Initial Comments at 22; Clean Energy Associations Initial Comments at 56-57; ENGIE Initial Comments at 11.

if possible.[2863] We clarify that, if an interconnection customer fails to operate its electric storage resource in accordance with the operating assumptions memorialized in the interconnection customer's LGIA, the procedure for termination pursuant to articles 17.1.1 and 17.1.2 of the *pro forma* LGIA is appropriate. We believe that repeat violations of the operating assumptions memorialized in the LGIA are likely not consistent with good utility practice.[2864] Additionally, we agree with rPlus and Idaho Power that there may be unique instances in real-time operations during which a transmission provider would want an electric storage resource to charge during peak load conditions (e.g., because the electric storage resource is located in a generation pocket). Therefore, we clarify that, if done so at the direction of the transmission provider to maintain the reliable and efficient operation of the transmission system, an electric storage resource that operates contrary to the operating assumptions specified in its LGIA in this instance must not be considered in breach of its LGIA by the transmission provider.

1522. We believe that, taken together, the revisions to the *pro forma* LGIP and *pro forma* LGIA will ensure that interconnection customers adhere to the operating

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[2863] Environmental Defense Fund Initial Comments at 6-7.

[2864] The *pro forma* LGIA states that "Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith." *Pro forma* LGIA art. 4.3 (Performance Standards).

assumptions used to study their electric storage resource and ameliorate concerns about possible reliability problems expressed by commenters. We agree with commenters that: (1) control devices can prevent electric storage resources from charging during peak load conditions; (2) modern electric storage resources can respond to signals from the transmission provider within seconds; (3) electric storage resources generally do not have an economic incentive to charge during peak load conditions; and (4) the consequence of being considered in breach of the LGIA provides an additional incentive for electric storage resources to follow the agreed-upon operating assumptions memorialized in their LGIA. Further, we note that some transmission providers already assume in their interconnection studies that electric storage resources will not charge during peak load conditions.[2865] We emphasize that, irrespective of these changes to operating assumptions, all electric storage resources must continue to meet all requirements in the *pro forma* LGIP and *pro forma* LGIA, as well as all applicable reliability standards.

1523. We agree with commenters that the speed and control with which electric storage resources can respond to signals from transmission providers sufficiently distinguishes the charging behavior of electric storage resources from that of firm customer end-use load. Therefore, for purposes of determining any network upgrades necessary to accommodate the reliable interconnection of electric storage resources, we find that the

[2865] Bonneville Initial Comments at 23; MISO Comments at 117; *see also PacifiCorp*, 182 FERC ¶ 61,131 (2023) (accepting, subject to condition, revisions to PacifiCorp's LGIP and LGIA to allow PacifiCorp to study electric storage resources in its interconnection study process using operating assumptions that more accurately reflect their expected operation).

charging of electric storage resources should not be modeled equivalently to firm customer end-use load in interconnection studies if the interconnection customer memorializes its operating assumptions in the LGIA and installs control technologies, if required, to limit its operations as specified.

1524. For clarity and in response to MISO's concern about conflicting descriptions of the reform in the NOPR preamble and the proposed revisions to the *pro forma* LGIP, we modify the proposed revisions to the *pro forma* LGIP to clarify that these requirements apply only to the operating assumptions for withdrawals of energy (e.g., proposed charging behavior of electric storage resources, whether standalone, co-located generating facilities, or part of a hybrid generating facility), not to discharging.

1525. In response to Pine Gate's request for clarification about what network upgrade costs will be allocated to interconnection customers as a result of the adoption of the revisions related to operating assumptions, we clarify that the transmission provider must not assign network upgrade costs to the interconnection customer based on those worst-case operating assumptions (e.g., charging at maximum capacity during peak load conditions) where there is agreement from the interconnection customer to, if required, implement operating restrictions including installing or demonstrating that the generating facility already has control technologies (software and/or hardware) to limit its operations during peak load conditions. As addressed above, we believe that these conditions sufficiently address any reliability concerns associated with the unexpected operation of an electric storage resource and thus believe it is appropriate for the transmission

provider to only assign costs for network upgrades based on the proposed charging behavior of the electric storage resource.[2866]

1526. Several commenters point out that not all transmission providers use the same process to study the charging of electric storage resources. Some transmission providers determine the network upgrades needed to accommodate the charging of an electric storage resource in the interconnection process, whereas other transmission providers do so exclusively as part of a transmission service request.[2867] In response to these commenters, we clarify that the requirement for transmission providers to use operating assumptions, at the request of the interconnection customer, in interconnection studies that reflect the proposed charging behavior of an electric storage resource applies only to the operating assumptions that transmission providers use in the interconnection process. This requirement does not apply to transmission service requests and this final rule does not propose to modify the process for requesting transmission service. In response to Puget Sound,[2868] we further clarify that this reform does not require transmission providers to study charging as part of the interconnection process if they do not already

[2866] *See, e.g.*, AEE Initial Comments at 41-42; AEP Initial Comments at 46-47; CESA Reply Comments at 10; Clean Energy Associations Initial Comments at 52, 56-58; NARUC Initial Comments at 37; NESCOE Reply Comments at 18; Public Interest Organizations Initial Comments at 48-50; R Street Initial Comments at 16; SEIA Reply Comments at 26-27.

[2867] *See, e.g.*, Clean Energy Associations Initial Comments at 55; Puget Sound Initial Comments at 11-12; SPP Initial Comments at 25; Tri-State Initial Comments at 22; Xcel Initial Comments at 46-47.

[2868] Puget Sound Initial Comments at 11-12.

do so. If a transmission provider does not determine the network upgrades needed to accommodate the charging of an electric storage resource through the interconnection process, then on compliance the transmission provider must demonstrate why this reform does not apply to that particular transmission provider.

1527. In the NOPR, the Commission sought comment on whether to define "peak load period" and/or "net peak load" period.[2869] Given the variation in the scenarios that transmission providers study in the interconnection process (e.g., summer peak load, winter peak load, shoulder peak load, light load conditions, etc.), we agree with commenters that regional flexibility is warranted.[2870] Therefore, we decline to adopt standardized definitions of "peak load period" and/or "net peak load" period.

1528. In the NOPR, the Commission also sought comment on whether to define firm and non-firm charging for electric storage resources and require transmission providers to define study criteria and possible ways to interconnect related to both firm and non-firm charging.[2871] Further, the Commission sought comment on proposed definitions of firm and non-firm charging service. Several commenters express concerns about defining firm and non-firm charging service, including whether the proposed definitions conflate interconnection and transmission service. We believe that, given the other reforms

[2869] NOPR, 179 FERC ¶ 61,194 at P 287.

[2870] *See, e.g.*, Ameren Initial Comments at 29; Microgrid Resources Initial Comments at 8.

[2871] NOPR, 179 FERC ¶ 61,194 at P 288.

adopted herein regarding operating assumptions, the proposed definitions of firm and non-firm charging service are not necessary to ensure that transmission providers, at the request of the interconnection customer, use more realistic operating assumptions to study electric storage resources in the interconnection process and to avoid excessive and unnecessary network upgrades that may otherwise hinder the timely development of new electric storage resources. Therefore, we decline to adopt any definitions of firm and non-firm charging service. As a result, we also clarify that this final rule does not require transmission providers to define conditions under which electric storage resources will be curtailed. In response to CAISO's concern that a proposed definition of firm charging service would require transmission providers that do not currently provide firm charging service to do so, we clarify that this final rule does not require transmission providers to provide firm charging service.

1529. In the NOPR, the Commission sought comment on whether to expand this reform to address operating assumptions for additional generating facility technologies that may currently be inaccurately modeled, such as variable energy resources.[2872] The Commission also sought comment on whether other operating assumptions, in addition to the assumption that electric storage resources withdraw energy during peak load periods, should be addressed as part of this proposed reform. In response to several commenters' concerns about potential reliability impacts and the administrative burden of extending the NOPR proposal to also address injections of power from electric storage resources or

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[2872] *Id.* P 286.

other resource types, we decline in this final rule to extend the reform to apply to additional generating facility technologies or to other operating assumptions. We clarify that this reform does not apply to the operating assumptions used to study the injection of power from electric storage resources or the injection of power from other resource types (e.g., natural gas, solar, wind, etc.). We encourage transmission providers to examine on an individual basis what operating assumptions used to study the injection of power may be appropriate to render the study process more accurate. Similarly, we decline to require transmission providers to use fuel-based dispatch assumptions to study the injection of power from all resource types in interconnection studies at this time, as suggested by some commenters. We acknowledge that fuel-based dispatch assumptions may be able to address some of the identified challenges associated with inaccurate modeling assumptions for all resource types and encourage transmission providers to evaluate the merits of adopting it, but we do not believe that adopting such a requirement on a generic basis is supported by the record.

1530. We decline to address the potential implications of this reform for transmission providers with Commission-approved interconnection processes that vary from the *pro forma* requirements adopted in Order Nos. 2003 and 845. As explained in the Section IV of this final rule, transmission providers with such variations from the *pro forma* LGIP and *pro forma* LGIA may seek approval as part of the compliance process to maintain those variations, which the Commission will consider on a case-by-case basis. What we adopt in this final rule are requirements that are part of the *pro forma* LGIP and *pro forma* LGIA, and we therefore only address the interaction of the requirements adopted

herein with existing requirements that are part of the *pro forma* process and not variations thereto.

1531. We also decline to require transmission providers to use standardized operating assumptions, as some commenters suggest.[2873] In the NOPR, the Commission did not propose to require transmission providers to use standardized operating assumptions, and we decline to do so here.

1532. In response to comments from Hydropower Commenters' suggestion that the final rule include a simplified procedure for amending an executed interconnection agreement to optimize the operating parameters of a pumped storage plant already in operation,[2874] we find that such a request is outside the scope of this proceeding. In the NOPR, the Commission did not propose a new study process for resources already in operation to amend operating assumptions memorialized in their interconnection agreements.

1533. In response to Microgrid Resources' request that the Commission explicitly include microgrids in the provisions of this rulemaking applied to hybrid resources,[2875] we find such a request to be outside the scope of this proceeding. The Commission did not propose to define microgrids or apply specific reforms to microgrids in the NOPR, and we decline to do so now. Further, in response to Microgrid Resources' and IREC's requests that the Commission extend the proposed reforms for hybrid resources to the *pro*

[2873] Puget Sound Initial Comments at 12; Pine Gate Initial Comments at 54.

[2874] Hydropower Commenters Initial Comments at 24.

[2875] Microgrid Resources Initial Comments at 7.

forma SGIP,[2876] we note that the NOPR did not propose to revise the *pro forma* SGIP to require transmission providers to use operating assumptions in interconnection studies that reflect the proposed charging behavior of an electric storage resource, and we decline to do so here.

2. Incorporating the Enumerated Alternative Transmission Technologies into the Generator Interconnection Process

a. Consideration of the Enumerated Alternative Transmission Technologies in Interconnection Studies Upon Request of the Interconnection Customer

i. Need for Reform and NOPR Proposal

1534. In the NOPR, the Commission stated that alternative transmission technologies can provide substantial benefits to optimize the transmission system in specific scenarios because they often can be deployed both more quickly and at lower costs than other network upgrades.[2877] The Commission stated that, despite these potential benefits, alternative transmission technologies often do not receive the same consideration during generator interconnection processes as other network upgrades.[2878] The Commission preliminarily found that failing to consider alternative transmission technologies that can be deployed both more quickly and at lower costs than network upgrades may render Commission-jurisdictional rates unjust and unreasonable.

[2876] *Id.*; IREC Initial Comments at 15, attach. A.

[2877] NOPR, 179 FERC ¶ 61,194 at P 294.

[2878] *Id.* P 296.

1535. The Commission proposed to revise the *pro forma* LGIP and *pro forma* SGIP to require transmission providers, upon request of the interconnection customer, to evaluate the requested alternative transmission solution(s) during the *pro forma* LGIP cluster study and the *pro forma* SGIP system impact study and facilities study within the generator interconnection process.[2879]

1536. To provide more certainty for evaluation purposes, and focus on technologies that serve a transmission function and thus are subject to Commission jurisdiction, the Commission proposed to specify the technologies that the interconnection customer may request to be evaluated.[2880] Specifically, the Commission proposed revisions to the *pro forma* LGIP and *pro forma* SGIP to require transmission providers to consider the following technologies within the cluster study of the *pro forma* LGIP and within the system impact study and facilities study of the *pro forma* SGIP upon request of the interconnection customer: advanced power flow control, transmission switching, dynamic line ratings, static synchronous compensators, and static VAR compensators. The Commission stated that it believes that the deployment of these transmission technologies may reduce interconnection costs by providing lower cost network upgrades to interconnect new generating facilities.[2881]

[2879] *Id.* P 297.

[2880] *Id.* P 298.

[2881] *Id.*; *see also id.* PP 294-95, 298.

1537. The Commission explained that, under this proposal, the interconnection customer may request, at the relevant scoping meeting, that the transmission provider consider a single, multiple, or all technologies on this list.[2882] The Commission proposed that the transmission provider would be required to evaluate the transmission technologies identified above for feasibility, cost, and time savings within the cluster study for the *pro forma* LGIP and the system impact study and facilities study for the *pro forma* SGIP, upon request of the interconnection customer. The Commission explained that the transmission provider, upon this request, must evaluate the identified transmission technology and, if feasible, determine whether it should be used, consistent with good utility practice and other applicable regulatory standards. Transmission providers would continue to retain discretion regarding whether to use the transmission technology.

1538. The Commission sought comment on whether the list of alternative transmission technologies is sufficient.[2883] In particular, the Commission sought comment on whether storage that performs a transmission function, synchronous condensers, and voltage source converters should be included in the list of alternative transmission technologies. The Commission also sought comment on: (1) whether there are software, operational, or other barriers to the use of these transmission technologies as proposed; (2) whether the use of alternative transmission technologies as supplements for, or in the place of, traditional network upgrades is sufficient to guarantee a level of service to accommodate

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[2882] *Id.* P 299.

[2883] *Id.* P 300.

an interconnection customer seeking NRIS, or whether such a network upgrade can only be used if the interconnection customer requested ERIS; (3) whether the existing study processes and models in the generator interconnection process remain suitable for considering alternative transmission technologies, whether additional processes or models are needed, and if so, which entity should be responsible for developing them; (4) how costs incurred for evaluating alternative transmission technology study requests would be allocated among interconnection customers in the cluster; (5) what reasonable number of transmission technology study requests from each interconnection customer would be workable, the burden (in terms of both time and resources) on transmission providers required to evaluate such requests, and whether interconnection study deadlines may need to be extended to account for time needed to evaluate the alternative transmission technology study requests; and (6) whether provisional interconnection service consideration for transmission technologies should be mandatory.[2884]

ii. <u>Comments</u>

(a) <u>Comments in Support</u>

1539. Numerous commenters support the Commission's proposal because they believe that it could reduce interconnection costs, increase flexibility, increase the speed of interconnections, and improve reliability.[2885] Commenters assert that the proposed

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[2884] *Id.* P 301.

[2885] ACORE Reply Comments at 3-4; AEE Initial Comments at 42; AEE Reply Comments at 41; AES Initial Comments at 25; Amazon Initial Comments at 5-6; Clean Energy Associations Initial Comments at 61-62; Clean Energy Associations Reply Comments at 9; Clean Energy Buyers Initial Comments at 5; Consumer Protection

alternative transmission technologies in the NOPR can reduce costs.[2886] With respect to reducing interconnection costs, SEIA contends that, by decreasing the costs of network upgrades, the proposal will reduce the number of withdrawals from the interconnection queue, creating a more stable and efficient interconnection process.[2887] SEIA also claims that decreasing these costs will reduce the interconnection costs for interconnection customers, who may then reflect those savings in power purchase agreements or integrated resource plan submissions.[2888] Commenters contend that, if the Commission were to not adopt this proposal, the failure to lower interconnection costs by evaluating alternative transmission technologies would impose unjust and unreasonable costs on interconnection customers.[2889]

Coalition Reply Comments at 2; CREA and NewSun Initial Comments at 92; EDF Renewables Initial Comments at 14; ENGIE Initial Comments at 12; EPRI Initial Comments at 20-21; Fervo Energy Reply Comments at 8-9; Illinois Commission Initial Comments at 14; Invenergy Initial Comments at 52; NARUC Initial Comments at 38-39; OSPA Reply Comments at 14; Ohio Commission Consumer Advocate Initial Comments at 15; OMS Initial Comments at 19; Ørsted Initial Comments at 3; Ørsted Reply Comments at 8; R Street Initial Comments at 9; SEIA Initial Comments at 41; Tesla Initial Comments at 8; WATT Coalition Initial Comments at 2; WATT Coalition Reply Comments at 1; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[2886] Cyprus Creek Initial Comments at 26; SEIA Initial Comments at 40; Shell Initial Comments, app. A at v-vi.

[2887] SEIA Initial Comments at 40; *see also* AEE Initial Comments at 42; EDF Renewables Initial Comments at 14; ENGIE Initial Comments at 12; Ørsted Initial Comments at 37; OMS Initial Comments at 19.

[2888] SEIA Initial Comments at 40-41.

[2889] Clean Energy Associations Reply Comments at 9-10; Environmental Defense

1540. With respect to reducing interconnection delays, Illinois Commission asserts, for example, that alternative transmission technologies allow resources to come online more quickly and allow for better use of the existing transmission system, requiring fewer transmission buildouts.[2890] OMS contends that failing to consider alternative transmission technologies risks requiring longer lead-time network upgrades.[2891] WATT Coalition argues that use of the appropriate technologies will result in fewer withdrawals from the interconnection queue and a reduction in restudies and delays.[2892] WATT Coalition points out that, when interconnection customers withdraw, grid enhancing technologies offer additional value because they are scalable and modular to address evolving needs and can be redeployed as those needs continue to change.[2893]

1541. With respect to reliability, Ohio Commission Consumer Advocate contends that some alternative transmission technologies could provide substantial benefits by resolving thermal overloads and avoiding voltage collapse.[2894]

Fund Initial Comments at 7; Fervo Energy Reply Comments at 9; NARUC Initial Comments at 38.

[2890] Illinois Commission Initial Comments at 14.

[2891] OMS Initial Comments at 19.

[2892] WATT Coalition Initial Comments at 2.

[2893] *Id.* at 2-3; WATT Coalition Reply Comments at 5-6.

[2894] Ohio Commission Consumer Advocate Initial Comments at 15.

1542. Some commenters argue that a requirement to study alternative transmission technologies would not slow down interconnection studies overall.[2895] For example, AEE states that, if a technology is not proven or commercially viable, it will be quickly ruled out of further evaluation under prevailing study approaches.[2896] ACORE claims that an evaluation of alternative transmission technologies would not be a burden but rather an integral part of interconnection studies because such an evaluation will likely reduce the number of withdrawals and restudies.[2897] WATT Coalition argues that, because transmission providers currently use an iterative process when conducting interconnection studies, adding the proposed list of alternative transmission technologies to an iterative solution set should not significantly change the time frame or complexity of studies.[2898]

(b) <u>Comments in Opposition</u>

1543. Some commenters argue that the proposal is unnecessary because transmission providers already consider alternative transmission technologies in interconnection studies.[2899] For example, Southern states that transmission providers already include the

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[2895] ACORE Reply Comments at 3-4; AEE Initial Comments at 44; ENGIE Initial Comments at 13; Fervo Energy Initial Comments at 7.

[2896] AEE Initial Comments at 44.

[2897] ACORE Reply Comments at 3-4.

[2898] WATT Coalition Reply Comments at 2.

[2899] Bonneville Initial Comments at 23-24; MISO Initial Comments at 120; MISO Reply Comments at 12; Southern Initial Comments at 29.

assessment of alternative transmission technologies such as static VAR compensators as needed in interconnection studies.[2900] AEE responds that, if alternative transmission technologies are already being evaluated, then the proposal will not place an additional burden on interconnection queues.[2901]

1544. Several commenters oppose the proposal because they believe it conflates the use of alternative transmission technologies in operations with their use in planning.[2902] For instance, MISO argues that alternative transmission technologies are not necessarily the solution needed for any particular interconnection because these are often operational solutions that are inappropriate for wide-scale deployment in a planning process, which reviews an entire cycle of proposed interconnections and identifies solutions to support those interconnections for the expected lifetime of their interconnection.[2903] MISO claims that using alternative transmission technologies in planning for interconnection rather than in operations may be inconsistent with "good utility practice" and "applicable regulatory standards", and MISO expresses concerns about the impact or effectiveness of using alternative transmission technologies in place of network upgrades.[2904] NYTOs

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[2900] Southern Initial Comments at 29.

[2901] AEE Reply Comments at 42-43.

[2902] MISO Initial Comments at 120; NRECA Initial Comments at 45-46; NYTOs Initial Comments at 32: PJM Initial Comments at 68.

[2903] MISO Initial Comments at 120; *see also* NRECA Initial Comments at 45-46.

[2904] MISO Initial Comments at 122-123.

assert that alternative transmission technologies should generally not be used in interconnection studies unless they are effective in the planning context.[2905] PJM argues that alternative transmission technologies should not be incorporated into the generator interconnection process because they do not represent long-term solutions that can serve as blanket substitutes for the need for transmission expansion.[2906] In response, AEE and WATT Coalition argue that the primary purpose of alternative transmission technologies is to serve as a complementary bridge technology while more robust transmission is built.[2907]

1545. Some commenters express concern that alternative transmission technologies are not always appropriate for addressing long-term, interconnection-related reliability issues.[2908] Southern adds that, because transmission providers already consider these technologies and are subject to mandatory reliability standards, interconnection customers should not be able to request certain reliability fixes because their overall focus may be to minimize cost instead of maximizing reliability.[2909] EEI asserts that

[2905] NYTOs Initial Comments at 32; *see also* Puget Sound Initial Comments at 13-14.

[2906] PJM Initial Comments at 68.

[2907] AEE Reply Comments at 43-44; WATT Coalition Reply Comments at 3-4.

[2908] AECI Initial Comments at 9; AEP Initial Comments at 51; Avangrid Initial Comments at 36; Southern Initial Comments at 29; U.S. Chamber of Commerce Initial Comments at 12.

[2909] Southern Initial Comments at 29.

building firm transmission capacity or replacing or upgrading limiting equipment provides a more reliable long-term solution than the use of alternative transmission technologies because they are not dependable for reducing congestion or providing more capacity in the long-term or during extreme system conditions.[2910]

1546. Ameren and EEI oppose the proposal because they assert it overlaps with pending proposals in other proceedings.[2911] EEI argues the Commission should not promulgate requirements related to alternative transmission technologies in this proceeding while other Commission proceedings meant to address the use of these same technologies are pending.[2912] ACORE responds that, given the benefits of incorporating alternative transmission technologies in interconnection studies, there is no justification for delaying this requirement pending action in the other Commission proceedings.[2913]

1547. Other commenters argue that requiring interconnection studies to consider alternative transmission technologies will increase interconnection study timelines and therefore slow interconnection request processing speeds, contrary to the NOPR's

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[2910] EEI Initial Comments at 20.

[2911] Ameren Initial Comments at 30; EEI Initial Comments at 20.

[2912] EEI Initial Comments at 21 (citing Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, Notice of Proposed Rulemaking, Docket No. RM20-10-000; Grid-Enhancing Technologies, Notice of Workshop, Docket No. AD19-19-000; Implementation of Dynamic Line Ratings, Notice of Inquiry, Docket No. AD22-5-000; Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking, Docket No. RM21-17-000).

[2913] ACORE Reply Comments at 4.

objective.[2914] Puget Sound asserts that "the time is not ripe" to enforce new standards concerning alternative transmission technologies, given the sweeping changes proposed in the NOPR, adding that advanced transmission technologies requirements may not be possible in the short term and could negate the Commission's goals to streamline the interconnection process.[2915]

1548. MISO contends that some alternative transmission technologies, e.g., technologies that can control line impedances, may shift the burden of system impacts to other parties by causing additional new constraints.[2916] Indicated PJM TOs are concerned that, if one interconnection customer request changes power flows, such as through the use of phase angle regulators, it will impact other interconnection customers and effectively require a whole additional set of studies for large areas of the transmission system.[2917] AECI argues that the appropriate balance of the burden to justify the use of a particular

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[2914] AECI Initial Comments at 9; AEP Initial Comments at 53; Avangrid Initial Comments at 35; Dominion Initial Comments at 41; EEI Initial Comments at 21; Eversource Initial Comments at 36-37; Indicated PJM TOs Initial Comments at 55; Indicated PJM TOs Reply Comments at 18; ISO-NE Initial Comments at 41; MISO Initial Comments at 11, 123; National Grid Initial Comments at 42-43; Puget Sound Initial Comments at 13.

[2915] Puget Sound Initial Comments at 13.

[2916] MISO Initial Comments at 122, 124.

[2917] Indicated PJM TOs Initial Comments at 55.

technology should rest with the interconnection customer so that "capricious study requests" are avoided.[2918]

1549. Several commenters argue that the NOPR proposal is overly burdensome for transmission providers.[2919] For instance, MISO TOs note the competing interests (i.e., accelerating the interconnection process and layering numerous additional requirements and significantly increasing the number of studies an RTO/ISO and its transmission owners must perform).[2920] MISO argues that the Commission's proposal would require MISO to conduct 4,780 evaluations in the first phase of its interconnection study process.[2921] MISO contends that, when evaluating how these technologies can be incorporated, the effects on the rest of the interconnection queue and system can generate debate that could slow down the interconnection process. Similarly, National Grid claims that new alternative transmission technologies can present modeling uncertainties (e.g., operating parameters and cost uncertainties) and potential software limitations that transmission owners would need an unforeseeable amount of time to evaluate and could lead to possible penalties if study deadlines are not met.[2922]

[2918] AECI Initial Comments at 9.

[2919] Dominion Initial Comments at 41; EEI Initial Comments at 21; Eversource Initial Comments at 36-37; MISO TOs Initial Comments at 30; NextEra Initial Comments at 6.

[2920] MISO TOs Initial Comments at 30.

[2921] MISO Initial Comments at 11.

[2922] National Grid Initial Comments at 42-43.

(c) Comments on Specific Proposal

(1) List of Alternative Transmission Technologies

1550. Some commenters broadly support the list of proposed alternative transmission technologies,[2923] with others supporting particular technologies (e.g., dynamic line ratings[2924] and advanced power flow control[2925]).

1551. MISO and SoCal Edison oppose the proposed list of technologies because they contend that it includes technologies that are not appropriate for interconnection.[2926] MISO asserts that, although the deployment of devices such as static series synchronous compensators could solve some problems, they could create other issues (e.g., a change to the impedance of any one transmission facility could cause problems or impact operations elsewhere), requiring the holistic management of their operation and deployment.[2927] SoCal Edison claims that certain technologies that the interconnection

[2923] NARUC Initial Comments at 39; OMS Initial Comments at 19; Ørsted Initial Comments at 16; WATT Coalition Initial Comments at 3; Xcel Initial Comments at 47.

[2924] Illinois Commission Initial Comments at 14; OMS Initial Comments at 19; WATT Coalition Initial Comments at 2; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[2925] WATT Coalition Initial Comments at 2; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[2926] MISO Initial Comments at 122; SoCal Edison Initial Comments at 20.

[2927] MISO Initial Comments at 122.

customer may request to be evaluated, such as dynamic line ratings, have not been fully tested by certain RTOs/ISOs and thus should be excluded from the permissible list of options requested by an interconnection customer.[2928]

1552. Some commenters assert that, although dynamic line ratings may be beneficial during operations, they may not be appropriate for interconnection or transmission planning.[2929] Others note several operational challenges of using dynamic line ratings in interconnection, such as: (1) there is currently no Commission or NERC guidance on how to use dynamic line ratings absent thorough data on wind conditions, temperature, and other future system conditions;[2930] and (2) interconnection study software is not capable of incorporating dynamic line ratings, and it is not clear what assumptions should be used on affected systems.[2931] ISO-NE argues that the Commission should continue to consider the use and implementation of this technology in Docket No. AD22-5, rather than here.[2932] In response, WATT Coalition argues that there is significant value in considering dynamic line ratings in planning, adding that dynamic line ratings and other

[2928] SoCal Edison Initial Comments at 20.

[2929] Indicated PJM TOs Initial Comments at 56; ISO-NE Initial Comments at 41; NYTOs Initial Comments at 32-33; PacifiCorp Initial Comments at 44; Tri-State Initial Comments at 23; U.S. Chamber of Commerce Initial Comments at 12-13.

[2930] PacifiCorp Initial Comments at 44.

[2931] Tri-State Initial Comments at 23.

[2932] ISO-NE Initial Comments at 41.

grid enhancing technologies are not more difficult to study than legacy devices and traditional solutions.[2933]

1553. While acknowledging the benefits that advanced power flow control devices provide for real-time operations, Indicated PJM TOs contend that they are inappropriate in the context of implementing solutions to facilitate interconnection.[2934] Tri-State claims that advanced power flow control devices may push power onto other affected systems, which is a more significant challenge in non-RTO/ISO scenarios.[2935] MISO asserts that the widespread use of advanced flow control devices can have widespread impacts due to sizeable adjustments to line impedances and that using these devices could result in a cascade of issues across the system, pushing the problem and the costs of remedying it to other customers.[2936] WATT Coalition asserts that automatic power factor controllers are just as effective at mitigating overloads as reconductoring but that automatic power factor controllers are the only flexible AC transmission system devices that suffer from the "perverse incentive" identified by stakeholders because installation costs are much lower than the upgrades they compete with.[2937] PacifiCorp states that in the course of the

[2933] WATT Coalition Reply Comments at 4-6.

[2934] Indicated PJM TOs Initial Comments at 56.

[2935] Tri-State Initial Comments at 23.

[2936] MISO Initial Comments at 122.

[2937] WATT Coalition Initial Comments at 3.

interconnection study process it often considers the use of advanced power flow control devices as potential alternatives to standard system infrastructure.[2938]

1554. Some commenters raise concerns about using transmission switching for interconnection. For instance, Tri-State questions whether transmission switching is meant to be a remedial action scheme or to create permanent open points on the system, which it argues may be problematic in non-RTOs/ISOs and may result in reduced reliability on the transmission system.[2939] MISO argues that applying automatic topology changes would be remedial action schemes, noting that MISO and its transmission owners have attempted to reduce the number of remedial action schemes employed on the system as a matter of good utility practice.[2940] PacifiCorp contends that transmission switching is a complex process that can be implemented only under particular factual scenarios and system conditions, adding that it is unlikely that system congestion could be reliably reduced by requiring the analysis of transmission switching in the study process.[2941]

1555. Other commenters argue that the Commission should not limit the alternative transmission technologies to a pre-approved list.[2942] Some commenters contend that the

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[2938] PacifiCorp Initial Comments at 43.

[2939] Tri-State Initial Comments at 23.

[2940] MISO Initial Comments at 122.

[2941] PacifiCorp Initial Comments at 44.

[2942] Amazon Initial Comments at 6-7; CTC Global Initial Comments at 17; ENGIE Initial Comments at 13; Environmental Defense Fund Initial Comments at 7; Invenergy

Commission's proposal could limit future grid enhancing technologies that might be the best solution because the list includes only five technologies and would not require transmission providers to consider new grid enhancing technologies until the list is expanded.[2943] AEE and ENGIE ask the Commission to provide a non-exhaustive list of alternative transmission technologies and allow any alternative transmission technologies or grid enhancing technologies that are proven and commercially viable to qualify for evaluation, consistent with the Commission's statutory obligation to "encourage, as appropriate, the deployment of advanced transmission technologies" and the list of alternative transmission technologies included in that statute.[2944]

1556. Commenters suggest adding the following technologies to the list: (1) synchronous condensers and voltage source converters;[2945] (2) IBR technology solutions for advanced control capabilities and control parameter tuning;[2946] (3) microgrid control technologies;[2947] and (4) remedial action schemes, which they contend are an effective and

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Initial Comments at 52; Microgrid Resources Initial Comments at 8; NRECA Initial Comments at 46; Public Interest Organizations Initial Comments at 53-55; Xcel Initial Comments at 47.

[2943] Ameren Initial Comments at 31-32; MISO Reply Comments at 13-14; Shell Initial Comments, app. A at v.

[2944] AEE Initial Comments at 44-45 (citing 42 U.S.C. 16422); ENGIE Initial Comments at 13.

[2945] NARUC Initial Comments at 39; Xcel Initial Comments at 47.

[2946] EPRI Initial Comments at 21.

[2947] Microgrid Resources Initial Comments at 8.

inexpensive way to mitigate local transmission constraints the use of which is not allowed in many transmission providers' policies.[2948]

1557. Several commenters also suggest adding advanced conductors to the required list of alternative transmission technologies.[2949] VEIR and ACORE argue that advanced conductors may be a beneficial alternative to network upgrades because: (1) advanced conductors meet the same criteria of quick deployment and low cost and have advantages over other network upgrades, especially the elimination of additional siting and permitting requirements;[2950] and (2) a recent Grid Strategies LLC report finds "short lead time to reconductor existing lines can help manage risk and uncertainties and significantly increase system capacity to mitigate overloads identified in interconnection studies."[2951] NARUC asks the Commission to consider requiring an evaluation of the accuracy of transmission line ratings on surrounding or impacted transmission facilities if requested by an interconnection customer.[2952] Additionally, Ampjack proposes tower

[2948] Enel Initial Comments at 80.

[2949] ACORE Initial Comments at 6-7; CTC Global Initial Comments at 6-9; VEIR Initial Comments at 5-7.

[2950] VEIR Initial Comments at 5-7.

[2951] ACORE Initial Comments at 7 (citing Jay Caspary and Jesse Schneider, Grid Strategies, LLC, *Opportunities to Use Advanced Conductors to Accelerate Grid Decarbonization*, at 9 (Feb. 2022), https://acore.org/wp-content/uploads/2022/03/Advanced_Conductors_to_Accelerate_Grid_Decarbonization.pdf).

[2952] NARUC Initial Comments at 39-40.

lifting to increase transmission line ratings due to the time savings, lack of outages, and use of existing structures.[2953]

1558. Many commenters recommend that the Commission add storage that performs a transmission function to the list.[2954] Illinois Commission contends that storage that performs a transmission function can relieve congestion, maintain reliability, and be placed on the transmission system more quickly and cheaply than building new transmission lines.[2955] Tesla suggests expanding the list to include batteries as virtual transmission, arguing that it provides several benefits (e.g., providing emergency capacity for congested transmission lines and surplus generation and surplus load capacity to allow operation of transmission lines closer to thermal capacity without risk of outage and averting the need for load shed by providing grid stability service).[2956] Clean Energy Associations note that the Commission has approved tariffs for storage that performs a

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[2953] Ampjack Initial Comments at 1-4.

[2954] AES Initial Comments at 25; Clean Energy Associations Initial Comments at 62; Clean Energy Associations Reply Comments at 9; ENGIE Initial Comments at 13; Illinois Commission Initial Comments at 14-15; Illinois CUB Reply Comments at 1; NARUC Initial Comments at 39; NESCOE Reply Comments at 19; NY Commission and NYSERDA Initial Comments at 10; Ohio Commission Consumer Advocate Initial Comments at 17; OMS Initial Comments at 19; Ørsted Initial Comments at 16; Tesla Initial Comments at 8-9; Union of Concerned Scientists Reply Comments at 14-15; Xcel Initial Comments at 47; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[2955] Illinois Commission Initial Comments at 14-15.

[2956] Tesla Initial Comments at 8-9.

transmission function. Clean Energy Associations assert that it would be inconsistent to prohibit an interconnection customer from adding electric storage to an interconnection request specifically to address transmission reliability impacts in lieu of conventional upgrades, while at the same time allowing an interconnection customer to add such storage to an interconnection request for purposes unrelated to transmission reliability or allowing an interconnection customer to limit electric storage operations as a means to avoid network upgrades.[2957]

1559. Other commenters do not agree with adding storage that performs a transmission function to the list.[2958] MISO notes that, although it already evaluates storage that performs a transmission function in its generator interconnection process, it was a subject of considerable debate.[2959] Shell states that, while storage that performs a transmission function may provide system benefits, it has concerns regarding the ability of storage that performs a transmission function to "queue jump" interconnection customers, thus putting those customers at a competitive disadvantage.[2960]

[2957] Clean Energy Associations Initial Comments at 62-63.

[2958] Ameren Initial Comments at 31; MISO Initial Comments at 121; Shell Initial Comments, app. A at v.

[2959] MISO Initial Comments at 121.

[2960] Shell Initial Comments, app. A at v.

(2) Whether to Mandate the Consideration of Alternative Transmission Technologies

1560. Several commenters argue that these technologies should be studied by default, rather than at the request of the interconnection customer, with some suggesting an "opt-out" that the interconnection customer could elect.[2961] Fervo Energy argues that mandating the consideration of grid enhancing technologies could be more efficient and facilitate more and faster interconnection, although there may be delays initially as transmission providers adjust.[2962] Clean Energy Associations ask that transmission providers automatically evaluate grid enhancing technologies, unless all interconnection customers in a cluster opt out.[2963] Ørsted recommends that the Commission consider requiring that advanced transmission technologies be studied and implemented when network upgrades are needed but cannot be completed within three years of being identified.[2964]

[2961] ACORE Initial Comments at 6; AEE Initial Comments at 42, 44; AEE Reply Comments at 41-42; Amazon Initial Comments at 6; Clean Energy Associations Initial Comments at 63-64; Environmental Defense Fund Initial Comments at 7; ELCON Initial Comments at 11; ENGIE Initial Comments at 13; Fervo Energy Reply Comments at 9; Hannon Armstrong Initial Comments at 2; Invenergy Initial Comments at 52-53; R Street Initial Comments at 16; WATT Coalition Initial Comments at 2; WATT Coalition Reply Comments at 1; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[2962] Fervo Energy Reply Comments at 9.

[2963] Clean Energy Associations Initial Comments at 63.

[2964] Ørsted Reply Comments at 8.

1561. CAISO contends that the Commission should simply require transmission providers to include a statement in their tariffs that they will consider alternative transmission technologies for every interconnection and incorporate them when they are the cost-effective solution.[2965] CAISO states that this would allow the interconnection customer to request an unexecuted interconnection agreement and to raise with the Commission any transmission provider refusal to consider a technology.[2966] Ohio Commission Consumer Advocate suggests that transmission providers and interconnection customers mutually determine an appropriate number of evaluations for grid enhancing technologies.[2967]

(3) <u>Alternative Transmission Technologies in Provisional Interconnection Service</u>

1562. Some commenters argue that alternative transmission technologies could assist with provisional interconnection service. For instance, R Street and Hannon Armstrong assert that these technologies can be used as a temporary measure until other network upgrades are completed, thus reducing the cost and delays of generator interconnection, even if they only serve as a bridge to a permanent solution set, such as cluster network upgrades.[2968] NextEra contends that, when an alternative transmission technology may

[2965] CAISO Initial Comments at 38.

[2966] *Id.*; *see also* MISO Reply Comments at 13.

[2967] Ohio Commission Consumer Advocate Initial Comments at 16.

[2968] R Street Initial Comments at 16; Hannon Armstrong Initial Comments at 2.

serve as a temporary solution, the transmission provider should reasonably cooperate with requests from an interconnection customer willing to fund installation of that technology as an interim solution.[2969] Fervo Energy asks the Commission to require transmission providers to consider alternative transmission technologies when responding to a provisional interconnection request if these technologies allow for earlier in-service dates.[2970]

1563. Others oppose requiring evaluation of alternative transmission technologies for provisional interconnection service.[2971] For instance, MISO argues that the consideration of advanced transmission technologies for provisional interconnection service should not be mandatory because it may result in delays that are contrary to the goals of this proceeding.[2972]

(4) Alternative Transmission Technologies for NRIS or ERIS

1564. Some commenters responded to whether the use of alternative transmission technologies can support an interconnection customer's request for NRIS, or whether the use of such technologies can only be used if the interconnection customer requested ERIS. Hannon Armstrong asserts that one or more of these alternative transmission

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[2969] NextEra Initial Comments at 38-39.

[2970] Fervo Energy Reply Comments at 10.

[2971] Ameren Initial Comments at 32; MISO Initial Comments at 124.

[2972] MISO Initial Comments at 124.

technologies may be able to delay or eliminate the needed network upgrades identified in interconnection studies under both ERIS and NRIS.[2973] MISO argues that technologies that merely curtail generation would not be suitable for interconnection requests seeking NRIS as they could not pass the deliverability test, while technologies that can control transmission line impedances, such as phase shifters, are acceptable for NRIS.[2974] Invenergy contends that a given alternative transmission technology may only facilitate ERIS service in certain circumstances but that there is no reason to limit the scope of alternative transmission technologies at the outset without having performed any relevant analysis.[2975] Clean Energy Associations ask the Commission to require transmission providers to publicly post any service differences (e.g., if use of a given technology would enable ERIS but not necessarily NRIS).[2976]

(5) Study and Network Upgrade Cost Allocation for Alternative Transmission Technologies

1565. Commenters address the Commission's question about how costs incurred for evaluating alternative transmission technology study requests would be allocated among interconnection customers in the cluster. WATT Coalition argues that any marginal increase of study costs to accommodate the evaluation of grid enhancing technologies

[2973] Hannon Armstrong Initial Comments at 2.

[2974] MISO Initial Comments at 124.

[2975] Invenergy Initial Comments at 53.

[2976] Clean Energy Associations Initial Comments at 62.

should be allocated evenly across interconnection customer cluster study participants.[2977] However, NARUC and Indicated PJM TOs disagree, asserting that additional costs incurred for evaluating alternative transmission technologies should be allocated to the requesting interconnection customer(s) to maintain cost certainty and equity.[2978] Fervo Energy proposes that, if the requested alternative transmission technology would benefit more than one interconnection customer in the cluster, a pro rata allocation of study cost among those interconnection customers would be appropriate; however, if the requested technology only serves one interconnection customer, Fervo Energy argues that direct cost allocation for that study cost is appropriate.[2979] Fervo Energy adds that it would support pro rata allocation of costs even if the Commission mandates consideration of alternative transmission technologies.[2980]

1566. NextEra argues that, under the "but for" principle of cost allocation, the interconnection customer's cost responsibility should be limited to the cost of the alternative transmission technology that would have sufficed as a long-term solution for a given network upgrade, especially when transmission providers choose instead to construct more costly upgrades beyond what is required for the interconnection

[2977] WATT Coalition Initial Comments at 4.

[2978] NARUC Initial Comments at 40; Indicated PJM TOs Reply Comments at 17-18.

[2979] Fervo Energy Initial Comments at 7.

[2980] Fervo Energy Reply Comments at 10.

customer's proposed generating facility.[2981] Tri-State instead argues that the Commission's proposal does not consider the likely outcome of an interconnection request advancing with a new technology, which will force the subsequent interconnection customer to fund costly network upgrades when it would be more equitable for the interconnection customers to share the cost of a single network upgrade.[2982]

(6) Timing of Alternative Transmission Technology Evaluation Requests

1567. Some commenters discuss limiting the request to include alternative transmission technologies to the initial stages of the interconnection process. ISO-NE and NESCOE argue that any alternatives that are proposed should be included in the initial interconnection request with specific assumptions that can be studied.[2983]

1568. Other commenters argue that interconnection customers should be able to request the study of alternative transmission technologies later in the interconnection process or when more information is available.[2984] Clean Energy Associations contend that transmission providers should be required to post the costs of requested technologies and

[2981] NextEra Initial Comments at 38.

[2982] Tri-State Initial Comments at 23.

[2983] ISO-NE Initial Comments at 41; NESCOE Reply Comments at 21.

[2984] EDF Renewables Initial Comments at 14-15; Enel Initial Comments at 79; Fervo Energy Reply Comments at 9; Invenergy Initial Comments at 55; Ørsted Initial Comments at 9.

give interconnection customers the flexibility to adopt appropriate solutions, subject to system conditions and any limitations in the area.[2985] Ørsted suggests that once cluster studies are done, and if the required upgrades are outside of the cluster area, then alternate transmission technologies, with the addition of energy storage, should be evaluated by the transmission provider during its system impact study phase.[2986]

1569. NARUC asks the Commission to ensure that there is an opportunity for information exchange between the transmission provider and interconnection customer to design alternative transmission technology solutions and supports implementation of a time frame to facilitate that information exchange.[2987] Ohio Commission Consumer Advocate contends that some changes would be required to address unique attributes of grid enhancing technologies that may be overlooked by existing frameworks and that the cost and duration of modeling and evaluations would be best addressed by transmission providers in concert with interconnection customers.[2988]

[2985] Clean Energy Associations Initial Comments at 62.

[2986] Ørsted Initial Comments at 9 (referencing definition of "alternative transmission technologies," NOPR, 179 FERC ¶ 61,194 at P 294 n.406).

[2987] NARUC Initial Comments at 40-41.

[2988] Ohio Commission Consumer Advocate Initial Comments at 16.

(d) Requests for Clarification and Flexibility

1570. Ameren asks how software or operational barriers (such as whether the MISO software can model the technology) will be addressed.[2989] Ameren asks for clarification as to who pays for the software necessary to model the alternative transmission technology and whether that gets assigned to the interconnection customer requesting the use of the advanced transmission technology or to the cluster of interconnection customers, some of which may prefer a different solution that does not involve use of an advanced transmission technology. Ameren claims that it is unclear what happens if interconnection customers within the same cluster disagree about using an alternative transmission technology in place of a network upgrade and whether consensus is required.

1571. NARUC suggests that the Commission clarify that transmission providers need not perform a separate study for each requested alternative transmission technology.[2990] NARUC also asks the Commission to clarify that interconnection customers bear the burden of designing the alternative transmission technology solutions, preparing necessary technical data, and determining whether it is temporary or permanent.

1572. NEPOOL urges the Commission to receive input from each RTO/ISO to consider how much flexibility to provide with respect to the list of alternative transmission technologies because they are the most informed with respect to which alternative

[2989] Ameren Initial Comments at 32.

[2990] NARUC Initial Comments at 40.

transmission technologies are feasible.[2991] Similarly, NYTOs ask the Commission to allow regions to determine which alternative transmission technologies would be appropriate and beneficial in performing interconnection studies instead of mandating their use.[2992]

1573. Some commenters underscore the importance of transmission providers retaining the discretion to decline to adopt an alternative transmission technology in the place of a network upgrade.[2993] National Grid argues that, to the extent an interconnection customer requests evaluation of a new alternative transmission technology beyond the list proposed in the NOPR and provides studies in support of its proposed use, the transmission owner should be permitted to determine whether the evaluation of such a new technology will be beneficial.[2994] Indicated PJM TOs request that, if the final rule requires transmission providers to consider alternative transmission technologies, the transmission provider and transmission owners have the ability to reject the request without a study when they have knowledge or experience that the request will not work.[2995]

[2991] NEPOOL Initial Comments at 17.

[2992] NYTOs Initial Comments at 32-33.

[2993] Ameren Initial Comments at 31; APS Initial Comments at 23; Indicated PJM TOs Initial Comments at 57; National Grid Initial Comments at 42; PacifiCorp Initial Comments at 43; Xcel Initial Comments at 47.

[2994] National Grid Initial Comments at 42.

[2995] Indicated PJM TOs Reply Comments at 17.

(e) Miscellaneous

1574. Invenergy argues that, if an alternative transmission technology is not selected, the transmission providers should provide detailed reports, including a cost-benefit analysis, behind the decision and there should be a process to resolve disagreements over the decision with the interconnection customer.[2996] R Street requests that the Commission require transmission providers to describe the benefits, or lack thereof, of the set of technologies listed in the NOPR.[2997] WATT Coalition and California Public Utilities Commissioner Darcie Houck request that transmission providers abide by strict standards when studying grid enhancing technologies.[2998]

1575. In addition to the study of alternative transmission technologies that the Commission envisions, Ørsted recommends requiring the deployment of these alternative transmission technologies as a medium-term or long-term alternative to transmission build out.[2999]

[2996] Invenergy Initial Comments at 54.

[2997] R Street Initial Comments at 16.

[2998] WATT Coalition Initial Comments at 3-4; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[2999] Ørsted Initial Comments at 16.

1576. EDF Renewables suggests that the Commission require the consideration of alternative transmission technologies not only in interconnection and transmission planning but also in market operations upon an interconnection customer's request.[3000]

1577. Enel claims that interconnection customer interconnection facilities are underutilized and could be networked into the transmission system to mitigate transmission constraints and to increase system reliability.[3001] Enel suggests that the Commission add language to the *pro forma* LGIA that allows interconnection facilities to convert to distribution facilities or regional transmission facilities.

iii. <u>Commission Determination</u>

1578. We adopt, with modifications, the proposed revisions to section 7.3 of the *pro forma* LGIP, and sections 3.3.6 and 3.4.10 of the *pro forma* SGIP. We modify the NOPR proposal to require transmission providers to evaluate the following enumerated list of alternative transmission technologies: static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, and tower lifting. We modify proposed *pro forma* LGIP section 7.3 to require transmission providers to evaluate the list of alternative transmission technologies enumerated in this final rule during the cluster study, including any restudies, of the generator interconnection process in all instances (i.e., for all interconnection customers in a cluster), without the need for a

[3000] EDF Renewables Initial Comments at 14-15.

[3001] Enel Initial Comments at 80-81.

request from an interconnection customer. We require transmission providers to evaluate each alternative transmission technology listed in *pro forma* LGIP section 7.3 and to determine, in the transmission provider's sole discretion, whether it should be used, consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements. Finally, we require transmission providers to include, in the *pro forma* LGIP cluster study report, an explanation of the results of the evaluation of the enumerated alternative transmission technologies for feasibility, cost, and time savings as an alternative to a traditional network upgrade.

1579. We modify the enumerated list of alternative transmission technologies from the NOPR proposal to: (1) retain synchronous, static VAR compensators, advanced power flower control, and transmission switching in the list; (2) add synchronous condensers, voltage source converters, advanced conductors, and tower lifting to the list; and (3) remove dynamic line ratings from the list. Generally, we find that these enumerated alternative transmission technologies are those with the most potential to be useful to reduce interconnection costs by providing lower cost network upgrades to interconnect new generating facilities and, thus, we require transmission providers to evaluate these technologies in the interconnection process for their feasibility, cost, and time savings potential.

1580. We also adopt, with modifications, the proposed revisions to sections 3.3.6 and 3.4.10 of the *pro forma* SGIP. Consistent with the *pro forma* LGIP requirement, we require transmission providers to evaluate the enumerated alternative transmission technologies in all instances, without the need for a request from an interconnection

customer. We modify the proposal to require such evaluations to occur during the *pro forma* SGIP feasibility study and system impact study of the generator interconnection process, as opposed to in the *pro forma* SGIP system impact study and facilities study. We find that it is appropriate to modify the proposal so that these evaluations occur during the relevant *pro forma* SGIP studies where network upgrades are identified, consistent with the *pro forma* LGIP requirement. We require transmission providers to evaluate each alternative transmission technology listed in *pro forma* SGIP sections 3.3.6 and 3.4.10 and determine, in the transmission provider's sole discretion, whether it should be used, consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements.

1581. Finally, we require transmission providers to include, in the feasibility study report and system impact study report, an explanation of the results of the evaluation of the enumerated alternative transmission technologies for feasibility, cost, and time savings as an alternative to a traditional network upgrade. We note that this reform is one of the few reforms in this final rule that applies to small generating facilities, in addition to large generating facilities. As described below, we find that the enumerated alternative transmission technologies that we are requiring transmission providers to evaluate in their interconnection studies are appropriate for evaluation in the *pro forma* SGIP context because they are scalable, and we find that the enumerated alternative transmission technologies have the potential to provide similar benefits in the context of both small and large generating facilities, including cost and time savings. As such, we adopt, with modifications, the proposed revisions to require transmission providers to evaluate the

enumerated alternative transmission technologies in all instances in both the *pro forma* LGIP and *pro forma* SGIP.

1582. This final rule does not create a presumption in favor of substituting alternative transmission technologies for necessary traditional network upgrades, either categorically or in specific cases.[3002] This final rule is agnostic as to whether, in a specific case, an alternative transmission technology is an acceptable alternative to a traditional network upgrade,[3003] "that would allow the interconnection customer to flow the output of its generating facility onto the transmission provider's transmission system in a safe and reliable manner."[3004] The determination in each specific case whether to require a

[3002] *See* PJM Initial Comments at 68 ("PJM therefore cautions the Commission not to conflate the operational benefits of alternative transmission technologies . . . with the need to address significant capacity enhancement needs (short and long-term) or long-range transmission needs under rapid growth or changing resource mix scenarios."); MISO Initial Comments at 120 ("However, the Commission fails to recognize that these technologies may be evaluated in the generator interconnection process already but may nonetheless not be adopted as they are not the appropriate solution to a Transmission Issue related to an interconnection.").

[3003] *See* MISO Initial Comments at 121-22 ("Further, although these technologies may be evaluated, the technologies identified by the Commission still may not provide the appropriate solution from a planning perspective.[] Many of the technologies identified are appropriately considered as operational tools or short-term solutions but are not necessarily appropriate for planning to support a particular generator interconnection.").

[3004] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 767 ("Both Energy Resource Interconnection Service and Network Resource Interconnection Service provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner"); Order No. 2003-A, 106 FERC ¶ 61,220 at P 404; *pro forma* LGIA art. 9.3 ("Transmission Provider shall cause the Transmission System and the Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with

traditional network upgrade or an alternative transmission technology is to be made by the transmission provider, and the determination should be consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements.[3005] This rule mandates a *process* of evaluation of alternatives to traditional network upgrades, not outcomes in specific cases.

1583. Based on the record, we affirm the Commission's preliminary finding in the NOPR that alternative transmission technologies have the potential to provide benefits to optimize the transmission system in specific scenarios.[3006] Specifically, a number of commenters argue that selecting alternative transmission technologies as network upgrades may reduce interconnection costs by providing lower cost transmission solutions to interconnecting new generating facilities[3007] and may allow for a faster

this LGIA"); *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,233, at P 190 (2012), *reh'g denied*, 139 FERC ¶ 61,253 (2012), *partial reh'g granted on other grounds*, 150 FERC ¶ 61,035 (2015). *See also pro forma* LGIA art. 9.4 ("Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA").

[3005] *See* MISO Initial Comments at 123 ("Additionally, as noted by the Commission in the proposed reform, although alternative transmission technologies may be useful tools for operations, relying on these tools for planning for interconnection may not be consistent with 'good utility practice' and 'applicable regulatory standards.'").

[3006] NOPR, 179 FERC ¶ 61,194 at PP 294-295.

[3007] AEE Initial Comments at 42; EDF Renewables Initial Comments at 14; ENGIE Initial Comments at 12; OMS Initial Comments at 19; Ørsted Initial Comments at 3; SEIA Initial Comments at 40.

interconnection by providing solutions that can be implemented more quickly.[3008] Commenters also point out that alternative transmission technologies allow for better use of the existing transmission system,[3009] can enhance reliability,[3010] and may reduce withdrawals, restudies, and overall interconnection delays.[3011] In addition, several commenters argue that decreasing the costs of network upgrades will reduce the number of withdrawals from interconnection queues, which will ultimately create a more efficient interconnection process by reducing the number of restudies triggered by withdrawals.[3012] Furthermore, commenters argue that alternative transmission technologies offer additional value because they are scalable and modular to address evolving needs and can be redeployed as those needs continue to change.[3013] We find that failing to evaluate the enumerated alternative transmission technologies renders Commission-jurisdictional rates

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[3008] AEE Initial Comments at 42; OMS Initial Comments at 19; Ørsted Initial Comments at 3; SEIA Initial Comments at 40.

[3009] Illinois Commission Initial Comments at 14; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[3010] AEE Initial Comments at 42; Ohio Commission Consumer Advocate Initial Comments at 15; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[3011] Ørsted Initial Comments at 3, 15-16; R Street Initial Comments at 16; SEIA Initial Comments at 40; WATT Coalition Initial Comments at 2.

[3012] SEIA Initial Comments at 41; WATT Coalition Initial Comments at 2.

[3013] WATT Coalition Initial Comments at 2-3; WATT Coalition Reply Comments at 5-6.

unjust and unreasonable and fails to ensure that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner.[3014]

1584. However, as stated above,[3015] this final rule mandates a process of evaluation of alternative transmission technologies, not outcomes in specific cases, and does not create a presumption in favor of using an alternative transmission technology as a substitute for a traditional network upgrade deemed necessary in a specific case. Rather, under the approach adopted here, in all cases, the transmission provider is required only to evaluate the use of alternative transmission technologies as network upgrades consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements.[3016] We recognize that, after the transmission provider evaluates the enumerated alternative transmission technologies, the transmission provider, in its sole discretion, may still decide to remedy an identified reliability problem with a traditional network upgrade.

1585. We modify the proposed requirement that transmission providers evaluate the enumerated alternative transmission technologies only at the request of the interconnection customer. Instead, we require transmission providers to evaluate the enumerated alternative transmission technologies in all instances, without a request from

[3014] NOPR, 179 FERC ¶ 61,194 at P 296; *see* Clean Energy Associations Reply Comments at 9-10; Environmental Defense Fund Initial Comments at 7; Fervo Reply Comments at 9; NARUC Initial Comments at 38.

[3015] *See supra* P 1582.

[3016] *See* MISO Initial Comments at 122-123.

an interconnection customer. We find that this approach both ensures that the enumerated alternative transmission technologies are considered in the interconnection process and avoids introducing additional procedural complexity to the interconnection process. This approach, which was suggested by many commenters,[3017] will provide the benefits of an evaluation of the enumerated alternative transmission technologies more broadly and consistently and in a more efficient manner. We believe that modifying the proposal addresses concerns raised by commenters about the NOPR proposal.[3018] More specifically, evaluating alternative transmission technologies only by request, as proposed in the NOPR, would create an overly complicated and time-consuming process under which transmission providers evaluate each alternative transmission technology for each interconnection request individually. Commenters also raise concerns about the impact on costs and timing for the entire cluster if only a portion of the cluster requests evaluation of alternative transmission technologies or if interconnection customers within the same cluster disagree about using an alternative transmission technology.[3019] Given

[3017] ACORE Initial Comments at 6; AEE Initial Comments at 42; CAISO Initial Comments at 38; Amazon Initial Comments at 6; ELCON Initial Comments at 11; Fervo Energy Reply Comments at 9; Hannon Armstrong Initial Comments at 2; Invenergy Initial Comments at 52-53; R Street Initial Comments at 16; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

[3018] Indicated PJM TOs Initial Comments at 55; MISO Initial Comments at 11, 121; MISO TOs Initial Comments at 30; National Grid Initial Comments at 42-43.

[3019] CAISO Initial Comments at 38; Puget Sound Initial Comments at 13; Ameren Initial Comments at 32.

these concerns, and the potential for benefits to be gained by the evaluation and use, at the transmission provider's sole discretion, of the enumerated alternative transmission technologies, we find that it would be overly burdensome and complex to require transmission providers to track and process interconnection customer-specific study requests and to resolve conflicts between interconnection customers' different study requests, at the expense of those benefits.

1586. The record before us demonstrates that the requirements we adopt today will not overly burden transmission providers.[3020] We find that requiring transmission providers to evaluate the enumerated alternative transmission technologies in each interconnection study will not be a significant additional burden on interconnection queues for those transmission providers that already consider alternative transmission technologies in their interconnection process. Furthermore, we find that the benefits of evaluating and implementing the enumerated alternative transmission technologies outweigh the potential burden or the potential of increased study times. As recognized by commenters and explained above, the evaluation and use, at the transmission provider's sole discretion, of the enumerated alternative transmission technologies could decrease network upgrade costs, withdrawals, and restudies, thereby increasing the efficiency of the interconnection process overall. For these reasons, we disagree with commenters that argue that requiring transmission providers to evaluate the enumerated alternative

[3020] AEE Initial Comments at 44; ENGIE Initial Comments at 13; ACORE Reply Comments at 3-4.

transmission technologies is contrary to the NOPR's goal of increasing the speed of interconnection queue processing.

1587. We find that, in conducting an evaluation of the enumerated alternative transmission technologies, it is appropriate for transmission providers to continue to retain discretion regarding whether to use each enumerated alternative transmission technology, consistent with the NOPR.[3021] The requirement is to *evaluate* the enumerated alternative transmission technologies in the interconnection process for feasibility, cost, and time savings and to determine whether, in the transmission provider's sole discretion, an alternative transmission technology should be used as a solution — consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements.[3022] The transmission provider must determine whether using any of the enumerated alternative transmission technologies is an appropriate and reliable network upgrade "that would allow the interconnection customer to flow the output of its generating facility onto the transmission provider's transmission system in a safe and reliable manner."[3023] The requirement to make such a determination

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[3021] NOPR, 179 FERC ¶ 61,194 at P 299.

[3022] *See* MISO Initial Comments at 122-123 ("Additionally, as noted by the Commission in the proposed reform, although alternative transmission technologies may be useful tools for operations, relying on these tools for planning for interconnection may not be consistent with 'good utility practice' and 'applicable regulatory standards.'").

[3023] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 767 ("Both Energy Resource Interconnection Service and Network Resource Interconnection Service provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner"); Order No. 2003-A, 106 FERC ¶

before allowing for the use of the enumerated alternative transmission technologies addresses concerns that their use may impinge on reliability, delay network upgrades instead of reducing the need for them or obviating the need for them altogether, or fail to address all transmission system issues that a traditional network upgrade would address. We recognize the need to avoid time-consuming delays and costly disputes or litigation over interconnection costs that could arise as a result of this reform.[3024] Therefore, we find that, if a transmission provider evaluates the enumerated alternative transmission technologies as required herein and, in its sole discretion, determines not to use any enumerated alternative transmission technologies as an alternative to a traditional network upgrade, the transmission provider has complied with this final rule, including tariffs filed pursuant to this final rule..

1588. Because we modify the NOPR proposal and require transmission providers to evaluate the enumerated alternative transmission technologies in all instances, we find

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61,220 at P 404; *pro forma* LGIA art. 9.3 ("Transmission Provider shall cause the Transmission System and the Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA"); *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,233, at P 190 (2012), *reh'g denied*, 139 FERC ¶ 61,253 (2012), *partial reh'g granted on other grounds*, 150 FERC ¶ 61,035 (2015). *See also pro forma* LGIA art. 9.4 ("Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA").

[3024] *See* SPP Initial Comments at 26 ("Even though the Commission has stated that transmission providers retain the discretion regarding whether to use such technologies, the very fact that the transmission provider is required to evaluate them will lead to disputes if the transmission provider then exercises that discretion.").

that the final rule will not "effectively require a whole additional set of studies for large areas of the transmission system" or exponentially increase the number of studies needed to consider the various combinations, as Indicated PJM TOs argue could occur under the NOPR proposal.[3025] This is because transmission providers will not be evaluating the enumerated alternative transmission technologies for a subset of interconnection customers within a cluster - but rather for the entire cluster.

1589. Regarding WATT Coalition and California Public Utility Commissioner Darcie Houck's request that transmission providers abide by strict standards when studying alternative transmission technologies,[3026] we decline to adopt any such standards in the *pro forma* LGIP and *pro forma* SGIP governing the evaluation of alternative transmission technologies. We find that it is appropriate to continue to rely on transmission providers to use good utility practice, applicable reliability standards, and other applicable regulatory requirements, in their evaluations of alternative transmission technologies, including the enumerated list, because the specific evaluation may depend on the transmission provider's individual transmission system, cluster makeup, and other factors. Similarly, regarding National Grid's concern that studying every potential alternative transmission technology for every interconnection request could cause

[3025] Indicated PJM TOs Initial Comments at 55.

[3026] WATT Coalition Initial Comments at 3-4; Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, recording at 1:16:18-1:24:02 (approx.) (Commissioner Darcie Houck) (July 16, 2023).

transmission providers to be penalized for not meeting study deadlines,[3027] the final rule does not require the study of all technologies considered alternative transmission technologies but rather the evaluation of the enumerated alternative transmission technologies. Further, we find that the transmission provider— consistent with good utility practice, applicable reliability standards, and other applicable regulatory requirements — retains the sole discretion to determine whether a particular technology in the enumerated list of alternative transmission technologies is appropriate and reliable as a network upgrade, or not, for a given cluster.

1590. We also believe that the requirement that transmission providers evaluate the enumerated alternative transmission technologies for an entire cluster—rather than on an individual interconnection customer-request basis—and the modifications to the enumerated list of alternative transmission technologies (as discussed below) will ease the burden on transmission providers, thereby lessening the risk that they are unable to complete studies by the required deadlines. We note that we are not dictating how a transmission provider must evaluate each enumerated alternative transmission technology on the list in each instance; we recognize that in some cases transmission providers may be able to rapidly determine if a certain enumerated alternative transmission technology is inappropriate for further study. In response to Invenergy's request that transmission providers should provide detailed evaluation reports on why an alternative transmission technology was not selected, transmission providers are required to include an

[3027] National Grid Initial Comments at 42-43.

explanation of the results of the evaluation of the required alternative transmission technologies for feasibility, cost, and time savings as an alternative to a traditional network upgrade in the applicable study report. However, we do not direct any additional detailed requirements related to this reporting requirement because we find they are not needed or appropriate. We find the required explanation of the results of the transmission provider's evaluation included in the applicable study report provides sufficient transparency without placing a further burden on transmission providers that would delay the processing of interconnection requests.

1591. Because we modify the NOPR proposal to require transmission providers to evaluate all the enumerated alternative transmission technologies in all instances, i.e., regardless of an interconnection customer requesting such an evaluation, we decline to adopt commenters' request to require transmission providers to evaluate the required alternative transmission technologies by default with an "opt-out" option for interconnection customers. We are not persuaded that there are benefits to including an "opt-out" option in the requirement, and we find it would be overly burdensome and complex to require transmission providers to track and process interconnection customers' requests to "opt-out" of the evaluation of certain alternative transmission technologies. Further, an "opt-out" would run contrary to our goal to have transmission providers evaluate the enumerated technologies in order to achieve beneficial outcomes like decreasing network upgrade costs, withdrawals, and restudies, thereby increasing the efficiency of the interconnection process overall.

1592. As discussed above, the enumerated alternative transmission technologies that transmission providers must evaluate in interconnection studies are: static synchronous compensators, static VAR compensators, synchronous condensers, advanced power flow control, transmission switching, voltage source converters, advanced conductors, and tower lifting. We discuss each technology in turn.

1593. Regarding synchronous and static VAR compensators, we find that, in providing reactive power to the transmission system, such devices could reduce interconnection costs by providing the voltage support where needed for the new generation facility being interconnected to operate reliably, rather than building a traditional network upgrade to resolve the voltage support issues. This potentially results in lower cost network upgrades to interconnect new generating facilities. ISO-NE states that it already evaluates static synchronous compensators when evaluating interconnection requests.[3028] Similarly, as Indicated PJM TOs attest, PJM already considers static synchronous compensators in its interconnection and transmission planning processes.[3029] Accordingly, we find that synchronous and static VAR compensators are appropriately included in the list of alternative transmission technologies enumerated in this final rule that transmission providers must evaluate in the interconnection process.

1594. Regarding advanced power flow controls, we find that these devices allow power to be pushed and pulled to alternate lines with spare capacity leading to maximum

[3028] ISO-NE Initial Comments at 41.

[3029] Indicated PJM TOs Initial Comments at 57.

utilization of transmission capacity and mitigation of overloads. Advanced power flow control devices can be scaled back as needed, providing an advantage over new lines or reconductors.[3030] PacifiCorp attests that it often considers the use of advanced power flow control devices as potential alternatives to standard system infrastructure, and Indicated PJM TOs note that PJM and PJM transmission owners already consider the appropriateness of power flow control devices when conducting interconnection studies.[3031] As discussed above, our decision to modify the NOPR proposal and require transmission providers to evaluate the enumerated alternative transmission technologies in all instances addresses Indicated PJM TOs' statement that evaluation of advanced power flow control devices in the interconnection process would significantly increase the complexity of interconnection studies and thus could cause delays in their completion.[3032] We acknowledge the possibility that use of advanced power flow control devices can have impacts on line impedance which may result in issues in other parts of the system, as suggested by MISO. However, the requirement of this Final Rule is merely that the transmission provider evaluate each alternative transmission technology, not that they deploy them in all circumstances. We appreciate, and expect, that if a transmission provider's evaluation demonstrates that deployment of advanced power flow control devices would create issues on the transmission provider's system as

[3030] AEE Initial Comments at 42.

[3031] PacifiCorp Initial Comments at 43; Indicated PJM TOs at 57.

[3032] *Supra* P 1585.

described by MISO, it will not select that advanced power flow control as the network upgrade.[3033]

1595. We also retain transmission switching on the enumerated list of alternative technologies in this final rule. Transmission switching can be used to route energy around areas with high congestion and improve the overall transfer capability of the system, potentially resulting in lower network upgrade costs. In regard to PacifiCorp's argument that transmission switching is a complex process that can be implemented only under very particular factual scenarios and system conditions, transmission providers are already required to evaluate the impact of the proposed interconnection on the reliability of the transmission system[3034] and thus should understand whether the factual scenarios and system conditions exist that would make a transmission switching solution appropriate. In response to Tri-State's question about whether transmission switching is meant to be a remedial action scheme or to create permanent normally open points on the system, this final rule does not prescribe how transmission providers deploy any of the enumerated alternative transmission technologies on their systems if they determine to use them. To Tri-State's concern that transmission switching solutions may be "problematic in highly interconnected systems not operating in an RTO/ISO," we reiterate that transmission providers retain the discretion to determine whether to deploy

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[3033] *See also infra* P 1602.

[3034] *See pro forma* LGIP section 7.3; *pro forma* SGIP sections 3.3.1, 3.4.1.

any of the enumerated alternative transmission technologies, including transmission switching solutions.

1596. We find that the record supports including synchronous condensers and voltage source converters to the list because these technologies similarly may reduce interconnection costs in situations where voltage support is a constraint and where a new or modified transmission line with these technologies may provide a lower cost network upgrade option to interconnect new generating facilities. Specifically, ISO-NE states that it already evaluates synchronous condensers when evaluating interconnection requests,[3035] and NARUC and Xcel urge the Commission to include evaluation of synchronous condensers and voltage source converters in the interconnection process.[3036]

1597. We also add advanced conductors and tower lifting to the list of alternative transmission technologies enumerated in this final rule. We note the comments arguing that advanced conductors may be beneficial as network upgrades.[3037] ACORE explains that deploying advanced conductors can significantly increase transmission capacity and allow for the interconnection of new generating facilities without the construction of new network upgrades.[3038] Similarly, we find that tower lifting has the potential to increase

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[3035] ISO-NE Initial Comments at 41.

[3036] NARUC Initial Comments at 39; Xcel Initial Comments at 47.

[3037] ACORE Initial Comments at 6-7; CTC Global Initial Comments at 6-9; VEIR Initial Comments at 5-6.

[3038] ACORE Initial Comments at 7 (citing Jay Caspary and Jesse Schneider, Grid Strategies, LLC, *Opportunities to Use Advanced Conductors to Accelerate Grid Decarbonization*, at 2 (Feb. 2022), https://acore.org/wp-

transmission line ratings by providing additional clearance from the ground.[3039] By increasing transmission line ratings, there will be more "headroom" on the system to address normal and contingency conditions identified in interconnection studies, and likely a reduced need for network upgrades.[3040] Given these potential benefits to interconnection customers, we require transmission providers to evaluate advanced conductors and tower lifting in the interconnection process.

1598. We remove dynamic line ratings from the list of enumerated alternative transmission technologies proposed in the NOPR. We agree with commenters that the technology may be less beneficial in the interconnection context than in the transmission operations and planning context because, for example, dynamic line ratings' ability to increase the available interconnection service depends on favorable weather and congestion parameters.[3041] That is, while dynamic line ratings may relieve congestion to increase available interconnection service temporarily or in the short-term, they may not

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content/uploads/2022/03/Advanced Conductors to Accelerate Grid Decarbonization.pdf).

[3039] *See* Ampjack Initial Comments at 4. As with other network upgrades, we note that tower lifting may require a modification to a certificate of public convenience and necessity (CPCN) or similar permit issued by a state utility regulator, which may include tower height limits or other physical restrictions. To the extent the transmission provider considers potential delays or the possibility of not receiving such a state CPCN modification when evaluating potential network upgrades, it should include a similar consideration in its evaluation of alternative transmission technologies.

[3040] *See id.* at 1, 4.

[3041] Indicated PJM TOs Initial Comments at 56; ISO-NE Initial Comments at 41; NYTOs Initial Comments at 32-33; PacifiCorp Initial Comments at 44; Tri-State Initial Comments at 23; U.S. Chamber of Commerce Initial Comments at 12-13.

be an adequate substitute for building interconnection facilities and/or traditional network upgrades identified through the interconnection study process that are needed to reliably interconnect a generating facility to the transmission system during all hours.

1599. We decline to add storage that performs a transmission function to the list of alternative transmission technologies enumerated in this final rule. The Commission has determined that the evaluation of whether a storage resource performs a transmission function requires a case-by-case analysis of either how a particular storage resource would be operated or the requirements set forth in a tariff governing selection of such storage resources. For example, in approving SPP's proposal to establish a framework under which an electric storage resource may be considered a transmission asset (thereby making the selected storage resources eligible for cost-based rate recovery through transmission rates), the Commission identified five considerations that, together, ensure that a selected storage resource will serve a transmission function.[3042]

1600. We clarify that transmission providers are not precluded from studying a technology that is not included in the enumerated list of alternative transmission technologies. Under the modified requirement, transmission providers must evaluate the enumerated alternative transmission technologies in all instances, but we are not precluding a transmission provider from studying or evaluating any other technology, including those such as dynamic line ratings that we have determined not to add to the list of technologies enumerated in this final rule. We acknowledge that certain transmission

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[3042] *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,153, at P 29 (2023).

providers already evaluate in certain studies transmission technologies not included in the final rule list.[3043] In addition, we clarify that, with respect to this final rule determination, transmission providers are not required to propose and justify on compliance any technology it studies in the interconnection process beyond those required in this final rule.

1601. In the NOPR, the Commission generally proposed a method to allocate the costs of cluster studies and the costs of network upgrades within a cluster through the interconnection study process.[3044] With respect to study costs, the Commission sought comment on how costs incurred for evaluating alternative transmission technology study requests would be allocated among interconnection customers in the cluster under a NOPR proposal in which interconnection customers would identify and request particular technologies to be studied.[3045] Given our modification to the NOPR proposal to require transmission providers to evaluate the enumerated alternative transmission technologies in the *pro forma* LGIP cluster study on behalf of the whole cluster, rather than upon an individual customer's request, we find that it is not necessary to consider alternative cost allocation methods for cluster study costs and network upgrade costs associated with the enumerated alternative transmission technologies. Specifically, we clarify that the

[3043] For example, PacifiCorp notes that it already considers advanced power flow technologies as potential alternatives to standard system infrastructure. PacifiCorp Initial Comments at 43.

[3044] *See* NOPR, 179 FERC ¶ 61,194 at PP 82-83, 88-89.

[3045] *Id.* P 301.

allocation of cluster study costs for, and substation and system network upgrades associated with, the enumerated alternative transmission technologies must be consistent with the allocation of costs for cluster studies and associated substation and system network upgrades for any other network upgrades because the enumerated alternative transmission technologies located on the high-side of the point of interconnection would fall within the definition of substation and system network upgrades,[3046] and they would be adopted only if they resolve system reliability issues triggered by an interconnection request. In other words, the enumerated alternative transmission technologies must be included among the set of options transmission providers consider when studying a cluster and any implemented enumerated alternative transmission technologies must receive the same cost treatment as any other option.

1602. Accordingly, the cost allocation concerns raised by several commenters in response to the NOPR proposal are now unfounded.[3047] Regarding MISO's concern that some alternative transmission technologies may shift the burden of system impacts to other parties,[3048] we find that the possibility of this burden shifting is minimal because the

[3046] Network Upgrades are "the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." *Pro forma* LGIP section 1 (Definitions).

[3047] AEP Initial Comments at 52-53; Ameren Initial Comments at 32; NextEra Initial Comments at 38; and Tri-State Initial Comments at 23.

[3048] MISO Initial Comments at 122.

revised *pro forma* LGIP, as adopted in this final rule, requires transmission providers to evaluate the enumerated alternative transmission technologies on a cluster-wide basis for feasibility, cost, and time savings. We recognize that, after the transmission provider evaluates the enumerated alternative transmission technologies, the transmission provider, in its sole discretion, may still decide to remedy an identified reliability problem with a traditional network upgrade.

1603. Regarding cost treatment for the enumerated alternative transmission technologies in the *pro forma* SGIP, the Commission did not propose to require, and this final rule does not adopt, cluster studies for small generator interconnection requests. Accordingly, the study process for small generating facilities in the *pro forma* SGIP remains a serial process and costs for evaluating the enumerated alternative transmission technologies must be allocated to the small generator interconnection request being studied. Likewise, the costs for any implemented enumerated alternative transmission technologies must be allocated to a small generator interconnection customer consistent with the allocation of any other network upgrade costs in the small generator interconnection process.

1604. As explained in Section III.A.3 of this final rule, we are not requiring transmission providers to allocate study costs on a pro rata basis, as Fervo Energy requests. Because this final rule does not adopt the NOPR proposal for interconnection customers to request the study of particular technologies, we need not address the arguments raised by NARUC and Indicated PJM TOs related to the study costs associated with that unadopted proposal.

1605. The Commission sought comment on whether transmission providers should be required to evaluate whether alternative transmission technologies can be deployed on a temporary basis to provide provisional interconnection service. We are not persuaded by arguments in favor of such a requirement. While we acknowledge commenters' arguments that alternative transmission technologies could serve as a temporary solution to reduce the overall costs and delays of generator interconnection, we agree with MISO that mandatory evaluation of alternative transmission technologies for provisional interconnection service could hinder ensuring that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner by adding burden and delay.[3049]

1606. The Commission also sought comment on whether alternative transmission technologies as supplements for, or in the place of, traditional network upgrades was sufficient to guarantee a level of service to accommodate an interconnection customer seeking NRIS, or whether such a network upgrade could only relate to ERIS.[3050] We agree with commenters that the enumerated alternative transmission technologies may enable NRIS, but such a determination will be dependent on the analysis by the particular transmission provider and the particular technology under evaluation. We decline to adopt Clean Energy Association's proposal that transmission providers be required to post additional information beyond the explanation of the results of the evaluation of

[3049] MISO Initial Comments at 124.

[3050] NOPR, 179 FERC ¶ 61,194 at P 301.

each alternative transmission technology. As discussed above, transmission providers must include, in the applicable study report, an explanation of the results of the evaluation of the enumerated alternative transmission technologies for feasibility, cost, and time savings.

1607. We find that the following commenters' proposals are outside the scope of this proceeding and, therefore, we do not address the substance: (1) requiring transmission providers to consider alternative transmission technologies in market operations at the request of the interconnection customer;[3051] (2) adding language to the *pro forma* LGIA that would allow interconnection facilities to convert to distribution or regional transmission facilities;[3052] and (3) requiring transmission providers to study and implement advanced transmission technologies when network upgrades are needed but cannot be completed within three years of being identified.[3053]

1608. Because we adopt a requirement for transmission providers to evaluate the enumerated alternative transmission technologies, rather than at the request of the interconnection customer, we do not address comments regarding the following issues, which become moot by this modification to the NOPR proposal: the timing of submission of the alternative transmission technology evaluation request;[3054] the burden of proof for

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[3051] EDF Renewables Initial Comments at 14-15.

[3052] Enel Initial Comments at 80-81.

[3053] Ørsted Reply Comments at 8.

[3054] Enel Initial Comments at 79; Invenergy Initial Comments at 55; *see also* EDF

a submission of an alternative transmission technology evaluation request;[3055] whether there should be a limit on alternative transmission technology evaluation requests;[3056] whether transmission providers and transmission owners should be able to reject alternative transmission technology evaluation requests;[3057] whether an interconnection customer can request evaluation of an alternative transmission technology not on the required list;[3058] and whether transmission providers need to perform a separate study for each requested alternative transmission technology.[3059]

1609. We do not find compelling commenters' request that the Commission not require the evaluation of alternative transmission technologies while other proceedings concerning grid enhancing technologies are pending.[3060] The Commission proposed and received extensive comment on evaluation of alternative transmission technologies in the interconnection process. Based on the record, we find that it is appropriate for the Commission to adopt a modified NOPR proposal to require transmission providers to evaluate the required list of enumerated alternative transmission technologies.

Renewables Initial Comments at 14-15; Fervo Energy Reply Comments at 9.

[3055] AECI Initial Comments at 9; NARUC Initial Comments at 40; ISO-NE Initial Comments at 41; NESCOE Reply Comments at 21.

[3056] EEI Initial Comments at 21.

[3057] Indicated PJM TOs Reply Comments at 17.

[3058] National Grid Initial Comments at 42.

[3059] NARUC Initial Comments at 40.

[3060] EEI Initial Comments at 20; *see also* Ameren Initial Comments at 30.

b. Annual Informational Report

i. NOPR Proposal

1610. In the NOPR, in order to add transparency to the evaluation process and deployment of alternative transmission technologies in generator interconnection processes, the Commission proposed to revise the *pro forma* LGIP and *pro forma* SGIP to require transmission providers to submit an annual informational report to the Commission that details whether, and if so how, advanced power flow control, transmission switching, dynamic line ratings, static synchronous compensators, and static VAR compensators were considered in interconnection requests over the last year.[3061] The Commission proposed to create a new docket to collect all annual informational report filings, and proposed that any informational reports that transmission providers file at the Commission would be for informational purposes and would neither be formally noticed nor require additional action by the Commission. The Commission sought comment on: (1) whether to require transmission providers to explain why an alternative transmission technology that was considered was not deployed; and (2) the scope of the annual informational report, and whether additional information should be included.

[3061] NOPR, 179 FERC ¶ 61,194 at P 302.

ii. Comments

(a) Comments in Support

1611. A broad group of commenters support the NOPR proposal.[3062] Many commenters agree that the reports would be beneficial to interconnection customers because they would provide insight as to why alternative transmission technologies were or were not deployed.[3063] Some commenters contend that the annual informational report will allow interconnection customers to better tailor their requests to consider alternative transmission technologies, such that those requests are most likely to be successful.[3064] Similarly, commenters argue that the annual informational reports would allow sharing of best practices in the industry on the use of these technologies and their evaluation, and would lessen concerns over the potential risks of new technologies by socializing examples of their consideration and implementation.[3065] ELCON and Fervo Energy assert that the annual informational reports will provide interconnection customers with

[3062] APPA-LPPC Initial Comments at 32; Clean Energy Buyers Initial Comments at 5; ELCON Initial Comments at 8; Enel Initial Comments at 81; Eversource Initial Comments at 37-38; CTC Global Initial Comments at 13; NARUC Initial Comments at 41; Pine Gate Initial Comments at 59; Public Interest Organizations Initial Comments at 55; SEIA Initial Comments at 41; WATT Coalition Initial Comments at 3.

[3063] NARUC Initial Comments at 41; Pine Gate Initial Comments at 59.

[3064] Pine Gate Initial Comments at 59.

[3065] CTC Global Initial Comments at 13; Eversource Initial Comments at 37-38.

additional information to ascertain the feasibility of certain configurations and interconnection points.[3066]

1612. Additionally, Enel states that transmission providers can be resistant to using advanced transmission technologies, and the annual informational report will allow the Commission to evaluate whether a transmission provider is artificially restricting the use of advanced transmission technologies, similar to the study completion metrics required by the Commission in Order No. 845.[3067] Some commenters argue that if the Commission observes that transmission providers are routinely citing certain technical or other reasons for not deploying certain technologies, the annual informational report will provide a record from which it can initiate action in a separate proceeding to remedy the issue.[3068]

1613. Several commenters argue in support of the annual informational report to promote transparency between market participants, interconnection customers, and regulators.[3069] Lastly, commenters argue that the additional work and obligation for the annual informational report would be an effective use of limited resources to benefit the efficiency, transparency, and modernization of the interconnection process.[3070]

[3066] ELCON Initial Comments at 8; Fervo Energy Reply Comments at 9-10.

[3067] Enel Initial Comments at 81.

[3068] CTC Global Initial Comments at 13; Pine Gate Initial Comments at 59.

[3069] Eversource Initial Comments at 37-38; NARUC Initial Comments at 41.

[3070] Enel Initial Comments at 81; Eversource Initial Comments at 37-38.

(b) Comments in Opposition

1614. Some commenters oppose the proposal on the basis that it would be too burdensome.[3071] Xcel Energy does not believe annual informational reports are necessary and requests that any informational reporting requirements be limited to decrease the burden on the engineers that need to focus on performing the interconnection studies.[3072] PacifiCorp states that imposing an additional reporting obligation on transmission providers would not only be duplicative, but it would add to an already significant list of administrative tasks that transmission providers must undertake to comply with existing, and proposed, interconnection obligations, without clear benefit.[3073] NYTOs believe that preparing and submitting an annual informational report with detailed analysis of the consideration of alternative transmission technologies would require dedicated resources on the part of the transmission provider.[3074] MISO asserts that the annual informational report at this time may not be useful, especially in the already transparent RTO/ISO context, and could divert scarce staff resources from the work of moving forward in the study and agreements process for implementing much-needed new generation.[3075]

[3071] Ameren Initial Comments at 33; CAISO Initial Comments at 39; MISO Initial Comments at 125; NYTOs Initial Comments at 33; PacifiCorp Initial Comments at 44; Xcel Initial Comments at 48.

[3072] Xcel Initial Comments at 48.

[3073] PacifiCorp Initial Comments at 44.

[3074] NYTOs Initial Comments at 33.

[3075] MISO Initial Comments at 125; MISO Reply Comments at 18.

Similarly, Indicated PJM TOs state that PJM currently maintains a publicly available website that details all the types of network upgrades necessary to support interconnections, including the types of devices identified here by the Commission.[3076] CAISO also opposes the proposal because CAISO believes that it is contrary to the goal of reducing interconnection queue backlogs by adding more studies and reporting requirements onto transmission provider staff.[3077]

1615. Idaho Power believes that the report may simply result in more disputes over why one entity allows a particular technology, while another one does not.[3078]

1616. CAISO and MISO also argue that there is limited value to interconnection reports.[3079] CAISO argues that in this NOPR, the Commission recognizes that imposing reporting requirements in Order No. 845 failed to incentivize transmission providers to meet their study obligations, and thus the Commission should not repeat that mistake here by burdening transmission provider staff with yet another reporting requirement.[3080] Similarly, MISO points out that neither the Commission nor any commenter used the

[3076] Indicated PJM TOs Initial Comments at 57-58.

[3077] CAISO Initial Comments at 38.

[3078] Idaho Power Initial Comments at 16.

[3079] CAISO Initial Comments at 39; MISO Reply Comments at 18-19.

[3080] CAISO Initial Comments at 39.

interconnection queue reports required by Order No. 845 to discuss the topic of study delays.[3081]

(c) Comments on Specific Proposal

1617. Several commenters emphasize the importance of transparency when an alternative transmission technology is not selected.[3082] ENGIE asks the Commission to require transmission providers to provide publicly available information addressing why or why not an alternative transmission technology was adopted or rejected in a specific case.[3083] CTC Global believes that transmission providers should be required to include explanations regarding the alternative transmission technologies considered, deployed, or rejected in the annual reports.[3084] CTC Global requests that the Commission also mandate reporting on the energy efficiency of the components used in various network upgrades and through the interconnection process.[3085] Eversource suggests that, in addition to the five technologies listed in the NOPR, transmission providers be allowed to provide reporting on any other grid enhancing technology or alternative transmission technology that was considered during the prior year.[3086]

[3081] MISO Reply Comments at 18-19.

[3082] CTC Global Initial Comments at 14, 17-18; ENGIE Initial Comments at 13; Eversource Initial Comments at 37-38; Fervo Energy Initial Comments at 7.

[3083] ENGIE Initial Comments at 13.

[3084] CTC Global Initial Comments at 17-18.

[3085] *Id.* at 14.

[3086] Eversource Initial Comments at 37-38.

1618. In contrast, Ameren argues that, if the Commission imposes this reporting burden on transmission providers, it should not further exacerbate the burden by requiring the transmission provider to also report explanations of common obstacles to the use of these alternative transmission technologies.[3087] Instead, Ameren states that the Commission should encourage interconnection customers and transmission providers to share with Commission staff through a technical conference or other forum the types of technologies being considered and whether adopted. Ameren suggests that this type of information gathering should be undertaken before the Commission imposes specific reforms or reporting requirements.

iii. <u>Commission Determination</u>

1619. We decline to adopt the NOPR proposal to require transmission providers to submit an annual informational report to the Commission that details whether, and if so how, the list of alternative transmission technologies were considered in interconnection studies over the last year. We are persuaded by commenters' arguments that the time and resources required to produce the annual informational report may hinder the ability to increase the speed of interconnection queue processing.[3088] We find that these challenges outweigh the incremental increased transparency to the evaluation process and deployment of alternative transmission technologies in generator interconnection

[3087] Ameren Initial Comments at 33.

[3088] MISO Initial Comments at 125; MISO Reply Comments at 18; NYTOs Initial Comments at 33; PacifiCorp Initial Comments at 44; Xcel Initial Comments at 48.

processes, particularly in light of additional reporting requirements in other parts of this final rule.

1620. Specifically, the annual informational report would be duplicative of the requirement in section 7.3 of the *pro forma* LGIP and sections 3.3.6 and 3.4.10 of the *pro forma* SGIP that we adopt in this final rule. Under these provisions, transmission providers must explain how the required alternative transmission technologies were evaluated for feasibility, cost, and time savings in each *pro forma* LGIP cluster study report or *pro forma* SGIP feasibility study and system impact study reports. The description of the results of the evaluation required in these reports should provide transparency into the evaluation process and deployment of alternative transmission technologies in generator interconnection processes. In response to Enel's argument that an annual informational report will allow the Commission to evaluate if a transmission provider is artificially restricting the use of alternative transmission technologies, we find that this concern is adequately addressed through the modified requirement that transmission providers evaluate all required alternative transmission technologies by default in all studies and restudies.

3. Modeling and Ride-Through Requirements for Non-Synchronous Generating Facilities

a. Modeling Requirements

i. Need for Reform and NOPR Proposal

1621. In the NOPR, the Commission preliminarily found that the *pro forma* LGIP and *pro forma* SGIP may be unduly discriminatory or preferential to the extent that they do

not require non-synchronous generating facilities to provide accurate and validated models to transmission providers during the generator interconnection process.[3089] Specifically, the Commission noted that, while Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP require all generating facilities to submit certain types of information, the information required is only sufficient to accurately model the behavior of synchronous generating facilities. The Commission stated its concern that, without a reform to require interconnection customers developing non-synchronous generating facilities[3090] to provide sufficiently accurate and validated models, interconnection studies may not identify the appropriate interconnection facilities and network upgrades, which could lead to unjust and unreasonable rates for interconnection service.[3091]

1622. The Commission proposed to revise Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP to ensure that all interconnection customers requesting to interconnect a non-synchronous generating facility must provide

[3089] NOPR, 179 FERC ¶ 61,194 at P 318.

[3090] Non-synchronous generating facilities are "connected to the bulk power system through power electronics, but do not produce power at system frequency (60 Hz)." They "do not operate in the same way as traditional generators and respond differently to network disturbances." *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 81 FR 40793 (June 23, 2016), 155 FERC ¶ 61,277, at P 10 n.24 (2016).

[3091] NOPR, 179 FERC ¶ 61,194 at P 319.

the transmission provider with the models needed for accurate interconnection studies.[3092] Pursuant to this proposal, interconnection customers requesting to interconnect a non-synchronous generating facility would be required to provide models that contain the details necessary to accurately model the performance of the generating facility in response to system disturbances in accordance with the control system settings that would be used by the interconnection customer during the commissioning and operation of the generating facility.

1623. Specifically, the Commission proposed to require each interconnection customer requesting to interconnect a non-synchronous generating facility to submit to the transmission provider: (1) a validated, user-defined root mean square (RMS) positive sequence dynamic model; (2) an appropriately parameterized, generic library RMS positive sequence dynamic model, including a model block diagram of the inverter control system and plant control system, that corresponds to a model listed in a new table of acceptable models or a model otherwise approved by WECC; and (3) a validated EMT model, if the transmission provider performs an EMT study as part of the interconnection study process.[3093]

1624. With regard to the validated, user-defined RMS positive sequence dynamic model, the Commission proposed to define a user-defined model as any set of programming code created by equipment manufacturers or developers that captures the latest features of

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[3092] *Id.* P 328.

[3093] *Id.* P 329.

controllers that are mainly software-based and represents the entities' control strategies but does not necessarily correspond to any particular generic library model.[3094] The Commission explained that in order for this model to be "validated," it must be confirmed that the equipment behavior is consistent with the model behavior, and described how the interconnection customer may make such confirmation.

1625. With regard to the appropriately parameterized, generic library RMS positive sequence dynamic model, the Commission proposed a table of acceptable generic library models based on the current WECC list of approved dynamic models for renewable energy generating facilities.[3095] The Commission noted that WECC's list of approved dynamic models has also been integrated into NERC reliability guidelines and that these models represent the current state of the art with regard to dynamic modeling requirements for non-synchronous generating facilities.

1626. The Commission stated that it believed that these models represent the full spectrum of modeling data that transmission providers need to perform accurate interconnection studies for non-synchronous generating facilities.[3096] The Commission also recognized that the modeling data proposed to be required from non-synchronous generating facilities may be more voluminous than that required of synchronous generating facilities; however, the Commission noted that this data submission

[3094] *Id.* P 330.

[3095] *Id.* P 331.

[3096] *Id.* P 332.

requirement is intended to result in a comparable level of modeling accuracy among all generating facilities.

1627. The Commission stated that an interconnection customer's failure to provide the above information within the deadlines established in the *pro forma* LGIP and *pro forma* SGIP would make the interconnection request incomplete and would be considered invalid in accordance with section 3.4.3 of the *pro forma* LGIP and section 1.3 of the *pro forma* SGIP.[3097] Pursuant to those provisions, if the interconnection customer does not cure the deficiency within the 10-business day cure period, the interconnection request will be considered withdrawn pursuant to section 3.7 of the *pro forma* LGIP and section 1.3 of the *pro forma* SGIP. The Commission also proposed to require that any proposed modification of the interconnection request be accompanied by updated models of the proposed generating facility.[3098]

1628. The Commission sought comment on: (1) whether the proposed reforms are necessary and/or sufficient to ensure that interconnection customers proposing non-synchronous generating facilities would submit models during the generator interconnection process that accurately reflect the behavior of their proposed generating facility; (2) whether the inclusion of the table based on NERC guidelines that cite WECC-approved models is appropriate; and (3) if not, how the Commission could

[3097] *Id.* P 333.

[3098] *Id.* P 334.

require interconnection customers to submit models that are widely known in industry to be accurate without listing specific models.[3099]

ii. Comments

(a) Comments in Support

1629. Many commenters support the NOPR proposal.[3100] SPP states that it has the highest penetration of IBRs[3101] of any RTO/ISO, so it is particularly sensitive to potential harm that could occur if those resources fail to perform as expected.[3102] ISO-NE argues that data issues are one of the largest causes of study delays in its region, and requiring data accuracy will improve study processing time and support first-ready, first-served

[3099] *Id.* P 335.

[3100] AEP Initial Comments at 54; APPA-LPPC Initial Comments at 33; APS Initial Comments at 24; CAISO Initial Comments at 39; Clean Energy Associations Initial Comments at 65; EEI Initial Comments at 23; NERC Initial Comments at 9-10; EPRI Initial Comments at 19; Eversource Initial Comment at 38; ISO-NE Initial Comments at 42; MISO Initial Comments at 125; MISO TOs Initial Comments at 33; NARUC Initial Comments at 42; National Grid Initial Comments at 44; North Carolina Commission and Staff Initial Comments at 27; NRECA Initial Comments at 48; NYTOs Initial Comments at 33; Ohio Commission Initial Comments at 17; OMS Initial Comments at 20; PacifiCorp Initial Comments at 45; PPL Initial Comments at 25; R Street Initial Comments at 17; SPP Initial Comments at 27; U.S. Chamber of Commerce Initial Comments at 13.

[3101] "Inverter-based resource" (IBR) refers to a resource that is asynchronously connected to the transmission system and is either completely or partially interfaced with the bulk power system through power electronics. *See* Reliability Guideline: BPS-Connected Inverter-Based Resource Performance, at vii, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf. The term "non-synchronous generating facilities" refers to the same resources.

[3102] SPP Initial Comments at 27.

reforms.[3103] NERC contends that the existing interconnection process does not provide sufficiently accurate and validated models for IBRs.[3104]

(b) Comments in Opposition

1630. Several commenters oppose the NOPR proposal in its entirety,[3105] while additional commenters express concerns about specific aspects. Pine Gate asserts that the Commission should not incorporate requirements into the *pro forma* LGIP and *pro forma* SGIP that are already being addressed by NERC through the standards development process.[3106] Pine Gate states that the *pro forma* LGIA and *pro forma* SGIA require interconnection customers to remain compliant with the applicable reliability standards, and recommends that the Commission address these modeling and performance reforms under the generic statement regarding compliance with applicable NERC Reliability Standards or by adding a similar statement in each applicable section of article 9 in the *pro forma* LGIA.[3107]

1631. NYISO argues that the final rule should not include a modeling requirement because it would be inefficient and necessitate a rebuild of NYISO's study base case.[3108]

[3103] ISO-NE Initial Comments at 42.

[3104] NERC Initial Comments at 18.

[3105] ENGIE Initial Comment at 13-14; NYISO Initial Comments at 53-54; Pine Gate Initial Comments at 60-61; SEIA Initial Comments at 41.

[3106] Pine Gate Initial Comments at 60.

[3107] *Id.* at 60-61 (citing *pro forma* LGIA art. 9.1).

[3108] NYISO Initial Comments at 53-54.

NYISO explains that, if the NOPR proposal is adopted, its interconnection study analysis would take much longer to ensure accurate results, significantly slowing the interconnection process.

1632. ENGIE argues that the required models in the NOPR proposal are very detailed, there are few consultants that perform this modeling, and the value obtained is low because the study likely will become outdated as project components are substituted for more advanced technologies. ENGIE recommends requiring a power flow and dynamic model, which it contends provides sufficient information on reliability impacts.[3109]

(c) Comments on Specific Proposal

(1) Cure Period for Modeling Information

1633. AES asserts that a 10-day cure period for interconnection customers to correct or provide additional information on models for non-synchronous generating facilities is not adequate and that no less than a 20 business-day cure period is needed.[3110]

(2) Transmission Provider Requirements

1634. SEIA requests that the Commission modify the NOPR proposal to require transmission providers to make available to interconnection customers the necessary system data needed to create accurate models, provide clear modeling requirements and

[3109] ENGIE Initial Comments at 13-14.

[3110] AES Initial Comments at 25-26.

validation guidelines and procedures,[3111] and engage stakeholders before making any modeling changes.

(3) Models Not Available Early in Interconnection Study Process

1635. Multiple commenters argue that accurate models for non-synchronous generating facilities may not be available early in the interconnection study process and may need to be updated during the process.[3112] Pine Gate and Public Interest Organizations assert that the Commission should revise the NOPR proposal to allow for later submission of such models to reduce the administrative burden on transmission providers and interconnection customers.[3113]

1636. SEIA requests that the Commission modify the NOPR proposal to require interconnection customers to provide all operating models within one year before the commercial operation date of the generating facility, so that the models reflect the most

[3111] SEIA Initial Comments at 42-43 (citing, e.g., CAISO, Electromagnetic Transient Modeling Requirements (Apr. 14, 2021), http://www.caiso.com/Documents/CaliforniaISOElectromagneticTransientModelingRequirements.pdf.).

[3112] Alliant Energy Initial Comments at 10-11; Clean Energy Associations Initial Comments at 66; EPRI Initial Comments at 17-18; NextEra Initial Comments at 40; Ørsted Initial Comments at 17; Pine Gate Initial Comments at 61; PPL Initial Comments at 25; Public Interest Organizations Reply Comments at 13; SEIA Initial Comments at 42.

[3113] Pine Gate Initial Comments at 61; Public Interest Organizations Reply Comments at 13.

accurate operating information.[3114] Clean Energy Associations assert that models requested very early in the interconnection study process, before product feature details have been finalized, may need to be updated prior to commercial operation, and argue that minor model changes should not result in excessive triggering of material modification rules.[3115]

1637. Alliant Energy and PPL state that technical information provided at the time an interconnection request is submitted can become outdated during the interconnection study process,[3116] and Alliant Energy asserts that the Commission should therefore provide for flexibility as to when and how required information for modeling requirements is provided.[3117] Ørsted argues that offshore wind interconnection customers may not be able to provide a validated model at the time of the interconnection request due to long lead times in generating facility development and equipment that is still being developed.[3118]

1638. EPRI suggests that an alternative approach to the NOPR proposal is to require the use of models that generally conform to the capability and performance standards Institute of Electrical and Electronics Engineers (IEEE) Standard 2800-022 and IEEE

[3114] SEIA Initial Comments at 42.

[3115] Clean Energy Associations Initial Comments at 66.

[3116] Alliant Energy Initial Comments at 10-11; PPL Initial Comments at 25.

[3117] Alliant Energy Initial Comments at 10-11.

[3118] Ørsted Initial Comments at 17.

Standard 1547-2018 during the interconnection study process, and notes that such studies are subject to further assessment once a detailed, site-specific model is available.[3119]

(4) <u>RMS Models</u>

1639. Several commenters request modifications to the proposed requirements for RMS models.[3120] Tesla and SEIA argue that the Commission should require transmission providers to accept user-defined library RMS positive sequence dynamics models, as these models better reflect the actual technology intended to be used by the resource, results in a much greater degree of modeling accuracy, and can help support greater penetration of renewable resources.[3121] In addition, Tesla suggests that the Commission seek informational submissions from transmission providers regarding software tools and resources needed to integrate more accurate user-defined RMS modeling. Clean Energy Associations argue that the transmission provider should have discretion to require a user-defined RMS model, a generic library RMS model (with site-specific parameterization), or both, instead of always being required to collect both.[3122] MISO encourages the Commission to require that the user-defined model be compatible with the

[3119] EPRI Initial Comments at 18.

[3120] Clean Energy Associations Initial Comments at 65-66; Eversource Initial Comments at 39; ISO-NE Initial Comments at 42-43; MISO Initial Comments at 125; SEIA Initial Comments at 43; Tesla Initial Comments at 11.

[3121] SEIA Initial Comments at 43; Tesla Initial Comments at 11.

[3122] Clean Energy Associations Initial Comments at 65-66.

transmission provider's software.[3123] Further, MISO requests that the Commission confirm that the user-defined model meets the transmission provider's MOD-032-1 requirements. Longroad Energy recommends that the Commission require NERC to improve the degree to which power flow software vendors allow accurate modeling of IBR technology before the Commission establishes modeling standards that might stifle technological improvements.[3124]

1640. Other commenters express concern with the difficulties of user-defined models.[3125] Eversource requests that the Commission specify that all positive sequence models provided must be non-proprietary and accessible to neighboring utilities, system operators, and other entities that need to access them.[3126] ISO-NE asserts that it does not accept user-defined models under its interconnection study procedures and requests that the final rule allow for a process where accurate, working, non-proprietary models are provided and screened in advance of the study process.[3127]

[3123] MISO Initial Comments at 125.

[3124] Longroad Energy Reply Comments at 20.

[3125] Eversource Initial Comments at 39; ISO-NE Initial Comments at 42.

[3126] Eversource Initial Comments at 39.

[3127] ISO-NE Initial Comments at 43.

(5) Model Validation

1641. Some commenters argue that the Commission should provide further direction regarding model validation requirements for non-synchronous generating facilities.[3128] NERC and SDG&E argue that reliability assessments indicate that model validation with actual installed equipment and a "true-up" of generator interconnection modeling would help ensure proper analysis and studies prior to commissioning.[3129] NERC recommends that the Commission enhance the interconnection process by ensuring more rigorous plant commissioning, with both the interconnection customer and the transmission provider signing off on models used in studies as compared with actual installed equipment.[3130] In addition, NERC asks the Commission to require transmission providers to conduct quality review of models before study and require interconnection customers to satisfy quality review milestones.[3131]

1642. Tesla argues that, in lieu of multiple attestations or test data, the Commission should develop an approach to validation that requires interconnection customers to

[3128] Clean Energy Associations Initial Comments at 66-67; NERC Initial Comments at 18-20; EPRI Initial Comments at 14-15; Ørsted Initial Comments at 16, 18; SDG&E Reply Comments at 3; Tesla Initial Comments at 10.

[3129] NERC Initial Comments at 18; SDG&E Reply Comments at 3.

[3130] NERC Initial Comments at 18.

[3131] *Id.* at 20.

submit "model-to-model" and "product-to-model" benchmarking data for non-synchronous generating facilities.[3132]

1643. Clean Energy Associations assert that the Commission should add language that provides that the attestation required for model validation be the best available by the original equipment manufacturer at the time of model delivery.[3133] In addition, Clean Energy Associations and Ørsted argue that the Commission should define the phrase "accurate and validated models."[3134] Clean Energy Associations explain that it is common practice to submit an interconnection request with advanced, next-generation equipment that the manufacturer may still be developing, in which case the product and validated models may not be available at the time of the interconnection request, and request that the Commission allow transmission providers flexibility to accommodate such new equipment in their interconnection studies.[3135]

1644. Clean Energy Associations and Ørsted assert that, if accurate and validated models require a comparison with unit level factory tests, then this may not be feasible for offshore wind farms, especially if they are connecting with HVDC transmission technology.[3136] They explain that these types of configurations are often project-specific

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[3132] Tesla Initial Comments at 10.

[3133] Clean Energy Associations Initial Comments at 66.

[3134] *Id.*; Ørsted Initial Comments at 16, 18.

[3135] Clean Energy Associations Initial Comments at 67.

[3136] *Id.* at 66-67; Ørsted Initial Comments at 16-17.

and do not have a definition of a "validated model." Ørsted also requests that the Commission explain why a "model block diagram of the inverter control system and plant control system" is necessary given the availability of WECC model block diagrams in simulation tools.[3137]

1645. EPRI argues that the Commission should modify the language in the *pro forma* LGIA and *pro forma* SGIA to ensure that all models are validated and appropriately parameterized.[3138] EPRI contends that the NOPR proposal fails to provide adequate directions and requirements with respect to model validation, testing, verification, and conformity assessment, as required during various stages of the interconnection process. EPRI asserts that a "validated" plant model would not be available during the interconnection study stage because validation of the plant model is not possible—within reasonable efforts—until after the commissioning and commercial operation of the generating facility. EPRI states that alternatives to this would be requiring generic models that are appropriately parametrized and conform to IEEE Standard 2800-2022 requirements.

(6) <u>Table of Acceptable RMS Models</u>

1646. Several commenters agree that a table of acceptable RMS models based on NERC guidelines that cite WECC-approved models is appropriate.[3139] Ameren asserts that the

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[3137] Ørsted Initial Comments at 18.

[3138] EPRI Initial Comments at 14-15.

[3139] Ameren Initial Comments at 34; Bonneville Initial Comments at 24; Shell

Commission should provide a table based on NERC guidelines that cite WECC-approved models as one but not the only example.[3140] Shell agrees that a table based on NERC guidelines is appropriate as long as the functionality and proprietary controls are adequately reflected (e.g., mimic the actual inverter performance of manufacturers' models).[3141] Shell explains that a generic model may not be able to support the operational characteristics of inverters. SPP states that, in its experience, some manufacturers do not support WECC-approved generic dynamics models and that having Commission support for more specific, detailed, and vetted modeling information requirements will be helpful to improve data quality and access.[3142]

1647. R Street and EPRI offer alternatives to a table based on NERC guidelines that cite WECC-approved models.[3143] R Street argues that providing a list of models in the final rule is not prudent given the dynamic nature of the table, and that the list should instead be posted on relevant public industry websites, including those of NERC.[3144] EPRI states that one alternative could be to include a reference and hyperlink to the NERC and

Initial Comments, app. A, at vi; Tri-State Initial Comments at 24.

[3140] Ameren Initial Comments at 34.

[3141] Shell Initial Comments, app. A, at vi.

[3142] SPP Initial Comments at 28.

[3143] EPRI Initial Comments at 20; R Street Initial Comments at 17.

[3144] R Street Initial Comments at 17.

WECC-approved models lists.[3145] EPRI also suggests that if the Commission retains the table, it should consider revising the description of the DER_A model to add the word "aggregated" to the description and also consider adding columns with the model names from other applicable software tools.

(7) EMT Modeling

1648. NERC and EPRI support the EMT modeling proposal in the NOPR.[3146] NERC recommends that all non-synchronous generating facilities perform EMT models prior to interconnection for consideration by transmission operators and planners.[3147] NERC contends that event analysis underscores the value of EMT studies in helping manage reliability risks of the modern transmission system.

1649. EPRI agrees that performing EMT studies should be at the discretion of the transmission provider.[3148] However, EPRI recommends collecting validated and appropriately parametrized EMT models during the interconnection process regardless of whether the transmission provider performs an EMT study because an EMT study may become necessary in the future, and the interconnection stage is the best time to obtain models due to the close coordination between interconnection customers, consultants, equipment manufacturers, and generating facility designers. EPRI also suggests that an

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[3145] EPRI Initial Comments at 20.

[3146] *Id.* at 15, 19; NERC Initial Comments at 21.

[3147] NERC Initial Comments at 21.

[3148] EPRI Initial Comments at 19.

industry-accepted generic EMT model could be required in lieu of a validated EMT model.[3149]

1650. Clean Energy Associations argue that the Commission should require submission of an EMT model one year before the scheduled commercial operation date of the non-synchronous generating facility if the transmission provider performs an EMT study as part of the interconnection study process.[3150] Clean Energy Associations assert that, if the Commission moves forward with a requirement for interconnection customers to provide EMT models, it should require the transmission provider and its consultants to protect these models with the highest degree of confidentiality because these models contain proprietary and highly commercially sensitive material that could pose a reliability risk if obtained by malicious actors.

1651. Several commenters oppose the EMT modeling proposal.[3151] AES contends that EMT modeling is not yet used widely in the industry and thus should not be adopted as a minimum standard.[3152]

1652. Longroad Energy argues that EMT studies are more expensive than transient stability studies, require highly specialized engineering experience to perform, and are

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[3149] *Id.* at 15.

[3150] Clean Energy Associations Initial Comments at 68-70.

[3151] AES Initial Comments at 26; Bonneville Initial Comments at 24; Invenergy Initial Comments at 57-58; Longroad Energy Reply Comments at 21; SEIA Initial Comments at 41-42.

[3152] AES Initial Comments at 26.

limited to modeling a fraction of a transmission provider's transmission system.[3153] Longroad Energy asserts that the Commission should continue to allow transmission providers the discretion to determine where such studies will meaningfully impact the interconnection requirements for an interconnection request. Further, Longroad Energy asserts that the Commission should require transmission providers to publish studies demonstrating the need for EMT studies to prevent unnecessarily imposing a costly, time-consuming step in the interconnection study process.

1653. SEIA asserts that EMT models are not yet industry standard models, require significant processing power compared to RMS models, and are not necessarily more accurate than RMS models.[3154] Bonneville asserts that it has found that EMT modeling studies are rarely necessary, and therefore any requirement to provide EMT models or studies should be left to the transmission provider's discretion.[3155]

(d) <u>Requests for Clarification</u>

1654. Invenergy requests that the Commission clarify that, if a validated EMT model is unavailable at the time of submission of an interconnection request: (1) whether the interconnection request may proceed and provide a generic EMT model, if available; and

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[3153] Longroad Energy Reply Comments at 21.

[3154] SEIA Initial Comments at 41-42 (citing Summary of the Joint Generator Interconnection Workshop, at 28 (Aug. 9-11, 2022), https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf (Generator Interconnection Workshop Summary)).

[3155] Bonneville Initial Comments at 24.

(2) if a validated EMT model is determined to be necessary, whether the interconnection customer may submit this information by the time of cluster restudy, or as soon thereafter as it becomes available from the manufacturer.[3156]

1655. APS requests clarity from the Commission on the process for curing deficiencies with respect to information provided by the interconnection customer, such as the number of times an interconnection customer is allowed to provide inaccurate data and cure deficiencies, before an interconnection request is deemed withdrawn.[3157]

(e) <u>Miscellaneous</u>

1656. ClearPath asserts that the Commission should consider how the NOPR proposal will align with technological advancements and supply chain challenges.[3158] ClearPath explains that the average interconnection queue wait time is 3.7 years, which may present opportunities for interconnection customers to adopt newer, more advanced equipment after they enter the interconnection queue. ClearPath further explains that supply chain challenges may force an interconnection customer to change equipment procurement unexpectedly while in the interconnection queue, and requests that the Commission explain whether a change in equipment that necessitates submitting new models and data is considered a material modification.

[3156] Invenergy Initial Comments at 58.

[3157] APS Initial Comments at 24.

[3158] ClearPath Initial Comments at 10.

1657. Consumers Energy notes that NERC is currently in the interconnection data gathering process, potentially making inclusion of additional requirements within the rulemaking duplicative and recommends consistency between NERC and Commission interconnection improvement efforts.[3159]

1658. EPRI states that the NOPR proposal does not specify information and data that the transmission providers may need to provide to the interconnection customer during the design stage (e.g., acceptable voltage ranges, protection details, short circuit levels, etc.).[3160] EPRI asserts that the final rule could consider the list of data from Annex H of IEEE 2800-2022, which includes definitions that could help define the combined generating and storage service level MW of a generating facility referred to in the NOPR proposal, including the continuous rating, continuous absorption rating, and short-term rating for IBRs.

iii. Commission Determination

1659. We adopt the NOPR proposal to revise Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP to require each interconnection customer requesting to interconnect a non-synchronous generating facility to submit to the transmission provider: (1) a validated user-defined RMS positive sequence dynamic model; (2) an appropriately parameterized generic library RMS positive sequence dynamic model, including a model block diagram of the inverter control system and plant

[3159] Consumers Energy Initial Comments at 9.

[3160] EPRI Initial Comments at 22.

control system, that corresponds to a model listed in a new table of acceptable models or a model otherwise approved by WECC; and (3) a validated EMT model, if the transmission provider performs an EMT study as part of the interconnection study process.

1660. We also adopt the NOPR proposals to: (1) define a user-defined model as any set of programming code created by equipment manufacturers or developers that captures the latest features of controllers that are mainly software-based and represent the entities' control strategies but does not necessarily correspond to any particular generic library model, as contained in Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP; (2) revise Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP to add a table of acceptable generic library models, based on the current WECC list of approved dynamic models for renewable energy generating facilities; and (3) revise section 4.4.4 of the *pro forma* LGIP and section 1.4 of the *pro forma* SGIP to require that any proposed modification of the interconnection request be accompanied by updated models of the proposed generating facility.

1661. Based on the record before us, we affirm the Commission's preliminary finding in the NOPR that the *pro forma* LGIP and *pro forma* SGIP are unduly discriminatory or preferential because they do not require non-synchronous generating facilities to provide accurate and validated models to transmission providers during the generator interconnection process that provide a comparable degree of accuracy as the models required of a synchronous generator. The current *pro forma* LGIP and *pro forma* SGIP

provisions ensure that synchronous generating facilities are required to provide accurate, validated models to transmission providers during the generator interconnection process. However, the current *pro forma* LGIP and *pro forma* SGIP provisions are insufficient to ensure that non-synchronous generating facilities submit models with a comparable level of accuracy.

1662. Additionally, we find that the lack of a requirement for non-synchronous generating facilities to provide accurate and validated models to transmission providers in the *pro forma* LGIP and *pro forma* SGIP results in unjust and unreasonable rates. Accurate and validated models are necessary to minimize study delays and to ensure that transmission providers conduct accurate interconnection studies that identify the necessary interconnection facilities and network upgrades to accommodate the interconnection request. Data issues are commonly cited as a major source of study delays, which contributes to interconnection queue backlogs.[3161] As described above, interconnection queue backlogs create uncertainty in the timing and cost of interconnecting to the transmission system and hinders the timely development of new generation. Moreover, without accurate models, transmission providers cannot conduct accurate interconnection studies that identify the appropriate interconnection facilities and network upgrades, leading to the inaccurate assignment of interconnection costs and resulting in Commission-jurisdictional rates that are unjust and unreasonable.[3162]

[3161] *See, e.g.*, ISO-NE Initial Comments at 42.

[3162] NARUC Initial Comments at 42; *see also* EEI Initial Comments at 23 (explaining that this requirement will improve transmission provider's ability to identify

1663. Furthermore, many commenters agree that this reform will help prevent potential reliability concerns if non-synchronous generating facilities do not perform when in service as modeled during the interconnection process.[3163] For example, additional modeling requirements will significantly improve the accuracy of both interconnection and reliability studies as well as address concerns regarding non-synchronous generation disturbance events.[3164]

1664. NYISO argues that the final rule would be inefficient and necessitate a rebuild of NYISO's study base case, take longer to ensure accurate results, and significantly slow the interconnection process.[3165] While we will not opine here on the NYISO-specific compliance with the final rule, we disagree that requiring accurate dynamic models of generating facilities will make the interconnection process take longer to ensure accurate results. To the contrary, we find here that a lack of accurate models is a major cause of study delays and contributes to interconnection study backlogs.

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appropriate interconnection facilities and network upgrades for non-synchronous generating facilities); MISO TOs Initial Comments at 33 (stating that the current lack of accurate modeling means that transmission providers are unable to fully assess their ability to respond to system disturbances).

[3163] APS Initial Comments at 24; CAISO Initial Comments at 39-40; Clean Energy Associations Initial Comments at 65; NERC Initial Comments at 9-10; Eversource Initial Comment at 38.

[3164] Eversource Initial Comment at 38.

[3165] NYISO Initial Comments at 53-54.

1665. The majority of commenters support the NOPR proposal.[3166] We affirm that, consistent with this final rule, all interconnection customers requesting to interconnect a non-synchronous generating facility must provide the transmission provider with the required models needed for accurate interconnection studies. We find that the models required herein contain the details necessary to accurately model the performance of the non-synchronous generating facility in response to system disturbances, and we decline to adopt alternative model proposals put forth by commenters. This reform promotes a consistent approach among all generating facilities with respect to modeling, such that all interconnection customers are required to submit information sufficient to accurately model the behavior of their proposed generating facilities.

1666. We decline to adopt AES's request for a 20-day cure period for model deficiencies.[3167] Under the proposed provisions, if an interconnection customer fails to provide the required models above within the deadlines established in the *pro forma* LGIP and *pro forma* SGIP, its interconnection request will be incomplete and considered

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[3166] AEP Initial Comments at 54; APPA-LPPC Initial Comments at 33; APS Initial Comments at 24; CAISO Initial Comments at 39; Clean Energy Associations Initial Comments at 65; EEI Initial Comments at 23; NERC Initial Comments at 9-10; EPRI Initial Comments at 19; Eversource Initial Comments at 38; ISO-NE Initial Comments at 42; MISO Initial Comments at 125; MISO TOs Initial Comments at 33; NARUC Initial Comments at 42; National Grid Initial Comments at 44; North Carolina Commission and Staff Initial Comments at 27; NRECA Initial Comments at 48; NYTOs Initial Comments at 33; Ohio Commission Initial Comments at 17; OMS Initial Comments at 20; PacifiCorp Initial Comments at 45; PPL Initial Comments at 25; R Street Initial Comments at 17; SPP Initial Comments at 27; U.S. Chamber of Commerce Initial Comments at 13.

[3167] AES Initial Comments at 25-26.

invalid in accordance with section 3.4.4 of the *pro forma* LGIP and section 1.3 of the *pro forma* SGIP. Pursuant to those provisions, if the interconnection customer does not cure such a deficiency within the 10-business day cure period, the interconnection request will be considered withdrawn pursuant to section 3.7 of the *pro forma* LGIP and section 1.3 of the *pro forma* SGIP. In it its request, AES provides no explanation for why the 10-business day cure period is insufficient. Moreover, we believe that the existing 10-business day cure period should be consistently applied to all interconnection request deficiencies and that having an extended cure period for model deficiencies would potentially introduce delays in the interconnection process. We note that interconnection customers may submit their interconnection requests early in the customer request window, which will allow for more time to ensure their models are valid.

1667. We disagree with Pine Gate that the revisions to the *pro forma* LGIP and *pro forma* SGIP, as adopted, incorporate requirements into the *pro forma* LGIP and *pro forma* SGIP that are already being addressed by NERC through the standards development process.[3168] We note that NERC supports the NOPR proposal and argues that the existing interconnection process does not provide sufficiently accurate and validated models for non-synchronous generating facilities to transmission providers.[3169] We find that these modeling requirements are appropriately addressed in the interconnection context, where interconnection customers must provide information to a

[3168] Pine Gate Initial Comments at 60.

[3169] NERC Initial Comments at 18.

transmission provider for use in interconnection studies, and thus adopt the revisions in the *pro forma* LGIP and *pro forma* SGIP. In addition, the *pro forma* LGIA and *pro forma* SGIA revisions apply to a wide spectrum of generating facilities, including newly interconnecting generating facilities that are currently outside the bounds of NERC's jurisdiction.[3170] As such, we find that this reform can holistically address the identified issues alongside the NERC standards; even if NERC is taking action, that need not prevent us from taking action here.

1668. We disagree with ENGIE that the value obtained from the models in the NOPR proposal is low because of the likelihood that the study will be outdated as project components are substituted with more advanced technology.[3171] We recognize that the project components for non-synchronous generating facilities may change during the interconnection process. We find, however, that this does not diminish the value of a transmission provider receiving the identified information from interconnection customers requesting to interconnect a non-synchronous generating facility and receiving models that represent the best information interconnection customers have available about their proposed generating facilities because these models will ensure that the transmission provider can accurately model the impact of the proposed generating facility

[3170] *But see Registration of Inverter-based Resources*, 181 FERC ¶ 61,124, at P 31, (2022) ("[W]e find it necessary to ensure that NERC register the owners and operators of those unregistered IBRs that, in the aggregate, have a material impact on Bulk-Power System reliability, to ensure those entities are subject to a relevant set of mandatory and enforceable Reliability Standard requirements.").

[3171] ENGIE Initial Comments at 13-14.

throughout the interconnection process. In addition, proposed section 4.4.4 of the *pro forma* LGIP and section 1.4 of the *pro forma* SGIP require that any modification of the interconnection request be accompanied by updates to the models. Pursuant to these provisions, the models are required to be updated as project components are changed. Ensuring that the model of the proposed generating facility is accurate throughout the interconnection study process will allow the interconnection customer to understand the actual, potential impact on their interconnection request of changing these project components as they are considering such technological advancements.

1669. Similarly, we disagree with commenters that argue that accurate models for non-synchronous generating facilities may not be available early in the interconnection study process and may need to be updated during that process.[3172] We find that the reforms we adopt herein are consistent with the principles behind other requirements in the *pro forma* LGIP and *pro forma* SGIP, namely those that set forth requirements for an interconnection request, including requirements that requests be viable and well-defined.[3173] The requirement to submit accurate models also reduces the chance that a transmission provider would need to perform additional studies, in this case if an interconnection customer submits models that are inaccurate and those inaccuracies are

[3172] Alliant Energy Initial Comments at 10-11; Clean Energy Associations Initial Comments at 66; EPRI Initial Comments at 17-18; NextEra Initial Comments at 40; Ørsted Initial Comments at 17; Pine Gate Initial Comments at 61; PPL Initial Comments at 25; Public Interest Organizations Reply Comments at 13; SEIA Initial Comments at 42.

[3173] *Pro forma* LGIP section 3.4.1; *pro forma* SGIP section 1.3.

not discovered until late in the interconnection process. In that instance, i.e., if model validation occurs at a point further into the interconnection process, inaccurate models that are used in interconnection studies could create errors in the studies, potentially leading to restudies and subsequent delays which would frustrate the efficiency gained by moving to a first-ready, first-served cluster study process. Further, we find that the definition of a validated model (i.e., confirmation that the equipment behavior is consistent with the modeled behavior) is sufficiently flexible to enable interconnection customers to provide such a model with their interconnection requests.[3174] Moreover, the option for the interconnection customer to submit an attestation that the models accurately reflect the expected behavior of a proposed generating facility would be based in the interconnection customer's best understanding at the time of the interconnection request, providing further flexibility if the interconnection customer chooses to change the equipment or control systems of the proposed generating facility, which is permitted as part of the interconnection process.

1670. In addition, we do not believe, as suggested by commenters,[3175] that there is a need to require transmission providers to make available additional information and system data in order for an interconnection customer to develop an RMS model. Although measured transmission system information is an input into the RMS model, the purpose of the model is to represent the behavior of the facility itself, and the interconnection

[3174] *Pro forma* LGIP Attachment A to Appendix 1.

[3175] SEIA Initial Comments at 42; Tesla Initial Comments at 11.

customer should be able to use likely transmission system configurations to parameterize and validate the RMS model. To the extent that the interconnection customer believes that actual transmission data is required to tune the model block diagram, the scoping meeting provides a venue for such discussions. The provisions set forth in new *pro forma* LGIP section 3.4.6 further detail scoping meetings, which occur during the customer engagement window.

1671. We decline to adopt requirements that constrain the discretion of transmission providers to use either user-defined RMS models or generic library RMS models, as suggested by commenters.[3176] We find that the transmission provider is in the best position to determine the power flow modeling method that is best suited to ensuring the reliability of its system.

1672. We decline to modify the NOPR proposal to allow the transmission provider to require *either* a user-defined RMS model *or* a generic library RMS model, as suggested by Clean Energy Associations, rather than requiring the interconnection customer to submit both, as adopted in this final rule.[3177] We believe that requiring the interconnection customer to submit both models is of value in providing the transmission provider discretion to choose which model most accurately represents a given generating facility's behavior. Providing these models does not represent an unreasonable burden on

[3176] Clean Energy Associations Initial Comments at 65-66; Eversource Initial Comments at 39; ISO-NE Initial Comments at 42-43; MISO Initial Comments at 125; SEIA Initial Comments at 43; Tesla Initial Comments at 11.

[3177] Clean Energy Associations Initial Comments at 65-66.

the interconnection customer, as the process of developing and parameterizing an RMS model is significantly simpler than doing so for an EMT model.

1673. We decline to require the user-defined RMS model to be compatible with the transmission provider's software and meet the transmission provider's MOD-032-1 requirements at the time the interconnection request is submitted, as requested by MISO.[3178] While the user-defined RMS model will have to meet these requirements prior to the cluster study for generating facilities seeking to interconnect pursuant to the *pro forma* LGIP and optional feasibility study or system impact study for generating facilities seeking to interconnect pursuant to the *pro forma* SGIP, the scoping meeting is the appropriate time to provide and discuss this information in order to correct the model if it is incompatible with the transmission provider's software or otherwise causes the transmission system model to be unable to solve.[3179]

1674. We decline to require NERC to improve the degree to which power flow software vendors allow accurate modeling of IBR technology, as requested by Longroad Energy.[3180] While we agree that improved accuracy of IBR modeling is beneficial, this rulemaking is focused on entities that execute, or request the unexecuted filing of, LGIAs

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[3178] MISO Initial Comments at 125.

[3179] The scoping meeting is a meeting between representatives of the interconnection customer and transmission provider "to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to affect such interconnection options," and "to analyze such information." Appendix C, *pro forma* LGIP section 1.

[3180] Longroad Energy Reply Comments at 20.

and SGIAs, and placing obligations on NERC or vendors is outside the scope of this proceeding. Equipment providers can develop and submit validated generic models to the software vendors' model libraries or the WECC model validation process to be included in the WECC table of approved models, if they desire to do so.

1675. In response to commenters that argue that the Commission should provide further direction regarding model validation requirements for non-synchronous generating facilities,[3181] we note that Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP, as adopted in this final rule, provide that, for a model to be "validated," the interconnection customer must provide evidence that the equipment behavior is consistent with the model behavior. In addition, Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP provide that this can involve, for example, an attestation from the interconnection customer that the model accurately represents the entire generating facility, attestations from each equipment manufacturer that the user-defined model accurately represents the relevant component of the generating facility, or test data. We find that this definition of a "validated" model and examples of an attestation in the proposal are sufficient and provide flexibility to allow interconnection customers to provide such a model with their interconnection requests. Therefore, we decline to adopt alternative proposals for model validation put forth by commenters.

[3181] EPRI Initial Comments at 14-15; Clean Energy Associations Initial Comments at 66-67; NERC Initial Comments at 18-20; Ørsted Initial Comments at 16, 18; SDG&E Reply Comments at 3; Tesla Initial Comments at 10.

1676. We decline to adopt alternatives and revisions to the table of acceptable generic library models based on the current WECC list of approved dynamic models for renewable energy generating facilities, as suggested by R Street and EPRI.[3182] We find that the table, as adopted, is appropriate because it represents the full spectrum of modeling data that transmission providers need to perform accurate interconnection studies for non-synchronous generating facilities. Nevertheless, we recognize that the list of models approved by WECC is subject to change and note that the table provides that "a model otherwise approved by [WECC],"[3183] and not reflected in the table, would also meet the model requirements.

1677. In response to commenters that oppose a requirement for a validated EMT model,[3184] we note that these concerns mischaracterize the NOPR proposal as mandating EMT models on a national basis. Rather, Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP, as adopted, requires that, in circumstances where the transmission provider performs an EMT study as part of its interconnection study process, the interconnection customer must provide an EMT model. We find that the transmission provider is in the best position to determine whether an EMT study is necessary to ensure system reliability because the transmission

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[3182] EPRI Initial Comments at 20; R Street Initial Comments at 17.

[3183] *Pro forma* LGIP, app. 1, attach. A; *Pro forma* SGIP, attach. 2.

[3184] AES Initial Comments at 26; Bonneville Initial Comments at 24; Invenergy Initial Comments at 57-58; Longroad Energy Reply Comments at 21; SEIA Initial Comments at 41-42.

provider has the in-depth knowledge of its transmission system required to recognize where and when regular dynamic modeling is inadequate to capture the true behavior of generating facilities.

1678. Similarly, we decline to adopt EPRI's request to require EMT models regardless of whether the transmission provider performs an EMT study.[3185] Developing an EMT model may place an unreasonable administrative burden on an interconnection customer in situations where such a model is not used by the transmission provider. We also decline to adopt EPRI's request to allow use of an industry-accepted, generic EMT model instead of a validated EMT model, as the record does not indicate that any such industry-accepted, generic models currently exist.[3186]

1679. We decline Clean Energy Associations' request that the Commission require submission of an EMT model one year before the scheduled commercial operation date of the non-synchronous generating facility if the transmission provider performs an EMT study as part of the interconnection study process.[3187] As noted above, we find that the proposal for models to be submitted with the interconnection request is consistent with the principles behind other requirements in the *pro forma* LGIP and *pro forma* SGIP and that transmission providers need these models to perform interconnection studies and ensure that prospective generating facilities do not create reliability risks to the

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[3185] EPRI Initial Comments at 19.

[3186] *Id.* at 15.

[3187] Clean Energy Associations Initial Comments at 68-69.

transmission system. In response to Clean Energy Associations' request that the Commission require the transmission provider and its consultants to protect the EMT models and other information with the highest degree of confidentiality,[3188] we note that the *pro forma* generator interconnection procedures and agreements include provisions for the treatment of confidential information.[3189]

1680. In response to Invenergy's request for clarification regarding whether a generic EMT model may be provided if a validated EMT model is unavailable at the time of submission of an interconnection request,[3190] we note that there is currently no industry-accepted generic EMT model; therefore, a validated EMT model is required. In response to Invenergy's request for clarification regarding whether the interconnection customer may submit this information by the time of a cluster restudy if a validated EMT model is determined to be necessary, we clarify that a validated EMT model, if required by the transmission provider, must be submitted with the interconnection request to proceed in the interconnection study process. As validation can consist of, for example an attestation from the interconnection customer that the model accurately represents the entire generating facility, based on the interconnection customer's understanding at the

[3188] *Id.* at 70.

[3189] *See pro forma* LGIP section 13.1; *pro forma* SGIP section 4.5; *pro forma* LGIA art. 22; *pro forma* SGIA art. 9.

[3190] Invenergy Initial Comments at 58.

time of submission, we believe an interconnection customer should be able to provide a validated EMT model at the time of the interconnection request.

1681. In response to APS' request for clarification on the number of times an interconnection customer is allowed to provide inaccurate data and cure deficiencies before an interconnection request is deemed withdrawn,[3191] we note that section 3.4.4 of the *pro forma* LGIP and section 1.3 of the *pro forma* SGIP provide the timeline for when a transmission provider must notify an interconnection customer that its interconnection request is deficient, and at that point, the interconnection customer has 10 business days to provide the additional requested information. We clarify that an interconnection customer has until the end of the 10 business-day period to cure deficiencies in its interconnection request. In the case of the *pro forma* LGIP, the interconnection customer may submit this information early in the cluster request window to ensure that there is sufficient time to address any issues with the interconnection request and the required models.

1682. In response to ClearPath's question regarding whether a change in equipment that necessitates submitting updated models is considered a material modification,[3192] we highlight that section 4.4 of the *pro forma* LGIP and section 1.4 of the *pro forma* SGIP set forth procedures for modifications to an interconnection request, including the evaluation of technical changes to a request. Further, we note that section 4.6 of the *pro*

[3191] APS Initial Comments at 24.

[3192] ClearPath Initial Comments at 10.

forma LGIP contains the transmission provider's technological change procedure, which was designed to allow transmission providers to evaluate whether equipment changes to an interconnection request should trigger the material modification provisions. A change in equipment may also qualify under the transmission provider's definition of permissible technological advancements in section 1 of the *pro forma* LGIP. This definition includes advancements that the interconnection process can accommodate without triggering the material modification provision of the *pro forma* LGIP.

1683. In response to Consumers Energy's recommendation that there should be consistency between NERC Reliability Standards and data collection efforts and the Commission's rulemaking,[3193] we are not persuaded that there is a conflict or duplication between this final rule and NERC's Reliability Standards and interconnection data collection efforts. NERC Reliability Standards apply only to entities that are registered with NERC. Many smaller non-synchronous generating facilities are currently excluded from NERC registration but interconnect under the *pro forma* SGIP and *pro forma* LGIP and execute, or request the unexecuted filing of, the *pro forma* SGIA or *pro forma* LGIA.[3194] The revisions to the *pro forma* interconnection procedures and *pro forma* interconnection agreements require all new interconnection customers that interconnect under the *pro forma* interconnection procedures and *pro forma* interconnection agreements to adhere to the new modeling requirements, regardless of whether the new

[3193] Consumers Energy Initial Comments at 9.

[3194] NERC Initial Comments at 13-14.

interconnection customers must abide by the NERC Reliability Standards. We also note that NERC supports the proposed reforms.[3195]

b. Ride Through Requirements

i. Need for Reform and NOPR Proposal

1684. In the NOPR, the Commission preliminarily found that the *pro forma* LGIA and *pro forma* SGIA ride through provisions could result in undue discrimination and preferential treatment.[3196] The Commission stated that, although synchronous and non-synchronous generating facilities are able to "ride through" system events and remain online and continue to provide real and reactive power following a disturbance, the existing *pro forma* LGIA and *pro forma* SGIA impose differing ride through requirements because they fail to account for a non-synchronous generating facility's ability to engage in momentary cessation.[3197] The Commission expressed concern that, given advances in inverter technology, the lack of performance requirements regarding the use of momentary cessation by non-synchronous generating facilities may not be supportable on either a technical or cost basis.[3198]

1685. The Commission proposed to require newly interconnecting non-synchronous generating facilities to continue current injection inside the "no trip zone" of the

[3195] *Id.* at 8-9, 18-20.

[3196] NOPR, 179 FERC ¶ 61,194 at P 320.

[3197] *Id.* PP 320-321.

[3198] *Id.* P 325.

frequency and voltage ride through curves of NERC Reliability Standard PRC-024-3 or its successor standards.[3199] The Commission explained that the *pro forma* LGIA defined the term "ride through" as the ability of the large generating facility to stay connected to and synchronized with the transmission system during system disturbances within a range of under-frequency and over-frequency conditions. The Commission proposed to expand this definition to include the ability of the large generating facility to stay connected to and synchronized with the transmission system during system disturbances within under-voltage and over-voltage conditions.

1686. In addition, the Commission proposed to require any newly interconnecting non-synchronous generating facility to have the ability, during abnormal frequency conditions and voltage conditions within the "no trip zone" defined by NERC Reliability Standard PRC-024-3 or its successor standards, to maintain power production at pre-disturbance levels unless providing primary frequency response or fast frequency response, and to have the ability to provide dynamic reactive power to maintain system voltage in accordance with the generating facility's voltage schedule.[3200] The Commission sought comment on whether adherence to these proposed requirements would be readily

[3199] *Id.* P 336. The "no trip zone" is defined as a set of voltage and frequency no trip boundaries within which applicable protection and controls may not be set to cause the generating facility to trip or cease current injection. *See* PRC-024-3 —Frequency and Voltage Protection Settings for Generating Resources, https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-3.pdf.

[3200] NOPR, 179 FERC ¶ 61,194 at P 337.

achievable through changes to control settings and whether such changes to control settings could be made at a relatively minor cost.[3201]

ii. Comments

(a) Comments in Support

1687. Many commenters generally support the goal of the NOPR proposal.[3202] CAISO asserts that the proposed reforms are essential for transmission providers to maintain reliability as non-synchronous generating facilities proliferate, and it urges the Commission to impose the proposed requirements on all interconnection customers that have not yet executed LGIAs as well as all prospective interconnection customers.[3203] CAISO argues that interconnection customers that have already procured certain inverters that cannot meet the requirements can request non-conforming LGIAs, or request that their LGIAs be filed unexecuted, but it notes that it recently implemented similar

[3201] *Id.* P 338.

[3202] AEP Initial Comments at 54; AES Initial Comments at 27; Ameren Initial Comments at 34; APPA-LPPC Initial Comments at 33; CAISO Initial Comments at 39-40; Consumers Energy Initial Comments at 9; NERC Initial Comments at 4, 23; Eversource Initial Comments at 38; Illinois Commission Initial Comments at 16; MISO TOs Initial Comments at 32-33; NARUC Initial Comments at 42; National Grid Initial Comments at 43-44; North Carolina Commission and Staff Initial Comments at 26-27; NRECA Initial Comments at 48; NYISO Initial Comments at 54; Ohio Commission Consumer Advocate Initial Comments at 17; PacifiCorp Initial Comments at 45; Pine Gate Initial Comments at 59; SPP Initial Comments at 28; U.S. Chamber of Commerce Initial Comments at 13.

[3203] CAISO Initial Comments at 39-40.

requirements, and interconnection customers have been able to procure the inverters and technology necessary to meet the requirements.

(b) Comments in Opposition

1688. Pine Gate asserts that the Commission should not incorporate requirements into the *pro forma* LGIP and *pro forma* SGIP that are already being addressed by NERC through the standards development process, which will add new requirements related to the vast majority of the modeling and performance issues identified in the NOPR.[3204] In addition, Pine Gate notes that the *pro forma* LGIA and *pro forma* SGIA already require interconnection customers to remain compliant with the applicable reliability standards.[3205]

(c) Comments on Specific Proposal

(1) IEEE Standards 2800 and 1547

1689. NERC and MISO support modifying the *pro forma* LGIP to incorporate elements of NERC Reliability Standards, NERC guidelines, and IEEE standards.[3206] Specifically, MISO supports adopting IEEE Standard 2800-2022 by reference in the *pro forma* LGIA.[3207] MISO asserts that implementing IEEE Standard 2800-2022 will ensure resource capabilities protect against the types of events described in several recent NERC

[3204] Pine Gate Initial Comments at 60.

[3205] *Id.* (citing *pro forma* LGIA art. 9.1).

[3206] NERC Initial Comments at 9; MISO Reply Comments at 26.

[3207] MISO Reply Comments at 25.

disturbance reports. NERC notes that the IEEE standards are inherently not mandatory unless a governing authority with jurisdiction adopts and enforces them and include many recommended practices that could be deemed informational.[3208] Accordingly, NERC asserts that IEEE Standard 2800-2022 operates similar to NERC reliability guidelines, although IEEE Standard 2800-2022 is only available upon purchase.

1690. NERC recommends that the Commission explicitly integrate the requirements and recommendations from IEEE Standard 2800-2022 into the *pro forma* interconnection agreements.[3209] Specifically, NERC contends that the Commission should prioritize the disturbance ride through, active power–frequency control, reactive power–voltage control, data sharing, and modeling provisions of IEEE Standard 2800-2022. However, NERC states that some transmission system conditions may require inverter control modes, settings, or protections that will not conform to IEEE Standard 2800-2022 region-wide expectations. NERC also argues that transmission providers should be permitted to establish additional performance requirements for specific locations and instances beyond region-wide requirements established under *pro forma* provisions, subject to transparency and public notice.

1691. Some commenters request that the Commission amend its proposal to reference IEEE Standard 2800 or successor standards for large generating facilities and IEEE

[3208] NERC Initial Comments at 3.

[3209] *Id.* at 6.

Standard 1547 for small generating facilities.[3210] EPRI asserts that these standards have been developed through a rigorous process and provide for IBR performance that supports system reliability while providing sufficient flexibility for RTOs/ISOs and interconnection customers.[3211] EPRI also notes that inverter manufacturers have publicly stated that state-of-the-art equipment already has the majority of the capabilities required by IEEE Standard 2800.

1692. EPRI argues that the Commission should consider narrowly specifying ride through requirements by reference to IEEE Standards 2800 and 1547; aligning all applicable definitions proposed in the NOPR with those standards; and evaluating the alignment of additional definitions or performance specifications with potential future revisions of those standards.[3212] EPRI asserts that failing to do so could create undue technical barriers to IBRs, and that paraphrasing of IEEE standards, rather than directly referencing the standards' requirements, could lead to an inconsistent implementation of the final rule in different regions with insufficient reliability benefits.[3213]

[3210] Clean Energy Associations Initial Comments at 73; EPRI Initial Comments at 5; SEIA Initial Comments at 43 (citing Generator Interconnection Workshop Summary at 20).

[3211] EPRI Initial Comments at 5.

[3212] *Id.*

[3213] *Id.* at 5-6.

1693. EPRI asserts that, if the Commission specifies its own ride through performance requirements, an alternative but less preferred approach would be to use the precise language and definitions as published in IEEE Standards 2800 and 1547.[3214]

1694. EPRI argues that the NOPR proposal does not seem entirely aligned with the NERC IBR guidelines and is not as clear as the applicable industry standards like IEEE Standard 2800-2022.[3215] EPRI also asserts that the Commission should consider what it characterizes as significant improvements in IEEE Standard 2800 over the NERC reliability guidelines. EPRI contends that the NERC IBR reliability guidelines cited in the NOPR did not fully consider all technical and stakeholder concerns considered by IEEE Standard 2800 and are therefore in contravention of the IEEE Standard 2800-2022 consensus requirements.[3216]

1695. SEIA states that IBRs are currently capable of riding through disturbances and that many developers have implemented controls to ensure they do so following the release of the consensus-based IEEE standards.[3217] SEIA argues that incorporating IEEE Standard 2800 into the *pro forma* LGIA would bring some certainty in generating facility design

[3214] *Id.* at 6.

[3215] *Id.* at 9.

[3216] *Id.* at 3.

[3217] SEIA Initial Comments at 43.

because the reliability requirements for each generating facility would be known at the time of the interconnection request.[3218]

(2) Feasibility of NOPR Proposal

1696. Some commenters argue that the proposed requirement in the NOPR "to maintain power production at pre-disturbance levels unless providing primary frequency response or fast frequency response" is not feasible.[3219] Invenergy asserts that, in order to increase reactive power output to maintain system voltage, a generator would necessarily have to reduce real power output: therefore, Invenergy requests that the NOPR proposal be revised to clarify this potential inconsistency.[3220] Clean Energy Associations and Public Interest Organizations contend that a requirement to maintain active power injection at pre-disturbance levels would lead to an undesirable response from generating facilities during a grid disturbance that could lead to voltage collapse, and the more helpful response would be to shift some power output to prioritize reactive power.[3221]

1697. Southern suggests adding a sentence to article 9.7.3 in the *pro forma* LGIA to address circumstances under which the generating facility is unable to maintain active

[3218] *Id.* at 44.

[3219] CAISO Initial Comments at 40; Clean Energy Associations Initial Comments at 71-72; NERC at 4; EPRI Initial Comments at 10; Invenergy Initial Comments at 58; Ørsted Initial Comments at 19-20; Public Interest Organizations Reply Comments at 14; Southern Initial Comments at 34.

[3220] Invenergy Initial Comments at 58.

[3221] Clean Energy Associations Initial Comments at 71-72; Public Interest Organizations Reply Comments at 14.

power while delivering reactive power.[3222] Clean Energy Associations suggest that the Commission replace the requirement to maintain active power production with language from NERC Reliability Standard PRC-024-3, which requires current injection and not active power injection to continue at pre-disturbance levels.[3223] Alternatively, Clean Energy Associations and Invenergy suggest the proposed language could be made more workable by only requiring a return to the pre-disturbance level of power production following voltage recovery, subject to the energy availability of the resource, which Clean Energy Associations explains would allow a generator to correctly shift from active power to reactive power during the voltage disturbance.[3224]

1698. CAISO requests that the Commission not require that inverters be able to provide real power during a transitory disturbance.[3225] CAISO states that, unlike synchronous generating facilities, IBRs are current limited and generally operate at their maximum output. CAISO argues that maintaining real power output at pre-disturbance levels would likely inhibit a non-synchronous generating facility's ability to provide reactive power during a disturbance, and to help ensure reliability CAISO recommends removing

[3222] Southern Initial Comments at 34 (suggesting the addition of the following sentence: "If the plant cannot maintain active power while delivering reactive power due to its current or apparent power limitation, then the preference should be given to either active or reactive power as specified by the Transmission Provider.").

[3223] Clean Energy Associations Initial Comments at 76.

[3224] *Id.* at 76-77; Invenergy Initial Comments at 58.

[3225] CAISO Initial Comments at 40.

the real power requirements and requiring non-synchronous generating facilities to provide reactive power at pre-disturbance levels. EPRI agrees that maintaining active power at the pre-disturbance levels during and after the abnormal voltage period may not be practical, given that voltage disturbances tend to be limited to a region relatively close to the fault location, and is not aligned with IEEE Standard 2800-2022 or other international requirements.[3226] EPRI and NERC recommend that IBR plant performance requirements should address active and/or reactive current during an abnormal voltage condition and requirements for the restoration of active power output in the post-fault period.[3227]

1699. EPRI argues that the implementation of frequency and voltage protection relay settings should not be exactly aligned with the NERC Reliability Standard PRC-024 curves but rather be based on the actual limits of equipment capability, with the objective to avoid potential damages.[3228]

1700. Ørsted argues that it is not possible to maintain real power production with depressed voltage that is still within the no trip zone of NERC Reliability Standard PRC-024-3, and explains that prioritizing reactive current during fault ride through mode (even within the no trip zone) is instrumental to maintain reliability.[3229] Ørsted

[3226] EPRI Initial Comments at 10.

[3227] *Id.* at 9-10; NERC Reply Comments at 4.

[3228] EPRI Initial Comments at 12.

[3229] Ørsted Initial Comments at 19-20.

recommends replacing the reference to good utility practice in proposed article 9.7.3 of the *pro forma* LGIA and instead rely on Order No. 842 and its definition of "Bulk-Power System – Primary Frequency Response."[3230]

1701. NERC notes that conventional grid-following IBRs are current-limited devices, and their active power output is voltage-dependent, making maintaining 100% of pre-disturbance active power while providing reactive power to support the bulk-power system during the fault period not always feasible.[3231] NERC recommends referring to "controls that maintain pre-disturbance active current (Ip)" in addition to the provision of reactive current (Iq) (i.e., reactive power support) rather than referring to "power."[3232]

(3) Applicability to All Types of Generating Facilities

1702. Invenergy asserts that the NOPR proposal should go beyond the *pro forma* LGIA's current requirements and apply evenly to all generating facilities, not just non-synchronous generating facilities.[3233] Similarly, Clean Energy Associations assert that the Commission currently only requires that relay settings not trip a generating facility during a voltage or frequency excursion and that there is no actual performance standard

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[3230] *Id.* at 20 (referring to *Essential Reliability Servs. & the Evolving Bulk-Power Sys. Primary Frequency Response*, Order No. 842, 83 FR 9639 (Mar. 6, 2018), 162 FERC ¶ 61,128, *order on clarification and reh'g*, 164 FERC ¶ 61,135 (2018)).

[3231] NERC Reply Comments at 4.

[3232] *Id.*

[3233] Invenergy Initial Comments at 58.

to ride through a disturbance for synchronous generating facilities.[3234] Clean Energy Associations assert that, to prevent undue discrimination, the Commission should either proceed with a similar effort to require ride through performance from synchronous generating facilities; or allow ride through performance exceptions for non-synchronous generating facility trips caused by auxiliary equipment performance, which are a primary cause of ride through failure for both synchronous and non-synchronous generating facilities.

1703. EPRI states that article 9.7.3 of the *pro forma* LGIA could benefit from additional modifications that differentiate between the ride through requirements for synchronous and non-synchronous large generating facilities because the two technologies have inherently different technical capabilities and operating principles.[3235]

1704. Ørsted urges the Commission to take note of the differences between technologies regarding their ability to ride through transmission system faults.[3236] For example, Ørsted states that it uses a plant controller for wind turbines that is frozen in fault ride through mode and that controls aiding voltage recovery are performed by individual turbines until voltage profile is back within a normal operating band of 90–110% of rated voltage. Ørsted concludes that not all non-synchronous generating facilities are subject to the

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[3234] Clean Energy Associations Initial Comments at 77.

[3235] EPRI Initial Comments at 11.

[3236] Ørsted Initial Comments at 16.

types of operating and power production concerns highlighted by the Commission in the NOPR.

(4) Proposed Revisions to the *Pro Forma* LGIA

1705. Ørsted asserts that interconnection customers can only "ensure" ride through capability of the generating and interconnection facilities per the definition in article 1 in the *pro forma* LGIA. Ørsted contends that the Commission's use of the term "transmission system" in article 9.7.3 of the *pro forma* LGIA is unclear in this context, and thus Ørsted alleges that it will be difficult to demonstrate compliance. Accordingly, Ørsted urges the Commission to use the term "generation and interconnection facilities" instead of "transmission system" in article 9.7.3 of the *pro forma* LGIA.[3237]

1706. Ørsted states that, in case of severe voltage dip, IBRs may freeze in phase locked loop, essentially holding the calculated angle of the external voltage at a certain value.[3238] Ørsted argues that this makes IBR units not strictly synchronized with the transmission system during this period.[3239] Accordingly, Ørsted asks the Commission to remove the phrase "stay synchronized" from article 9.7.3 of the *pro forma* LGIA.

[3237] *Id.* at 18-19.

[3238] A "phase locked loop" is a circuit that synchronizes an output signal with a reference or input signal in frequency as well as phase. Roland E. Best, *Phase-Locked Loops: Design, Simulation and Applications*, at 1 (6th ed. McGraw-Hill 2007).

[3239] Ørsted Initial Comments at 19.

(d) Requests for Clarification and Miscellaneous

1707. NV Energy questions the ramifications of non-synchronous generating facilities failing to maintain a composite power delivery at continuous rated power output at the high side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging.[3240] NV Energy suggests in this circumstance the non-synchronous generating facilities make a payment for failing to maintain the tariff-required composite power delivery. NV Energy notes that there is a pending reactive power rulemaking and inquires whether the industry should assume that payments for reactive power will be addressed in that rulemaking.

1708. Eversource requests that the Commission clarify that transmission providers may include additional performance requirements in the LGIA appendices for non-synchronous generating facilities that are necessary to ensure reliable interconnection in a given area, such as harmonics or radio frequency interference.[3241]

1709. Invenergy asserts that the Commission should not rely entirely on ride through and other burdens on interconnection customers to address larger transmission system issues that should be addressed through regional transmission planning processes.[3242]

1710. EPRI states that addressing how to apply grandfathering to existing facilities is an important consideration that should be addressed through Commission/NERC

[3240] NV Energy Initial Comments at 8.

[3241] Eversource Initial Comments at 38-39.

[3242] Invenergy Initial Comments at 59.

requirements. EPRI suggests that the Commission could add a procedure and criteria for a transmission provider to waive the grandfathering rule and require retrofits of existing facilities at the time of plant changes, or upgrades to meet the specified performance and modelling requirements, or to meet specific capability and performance standards such as IEEE Standard 2800-2022.[3243]

iii. Commission Determination

1711. We adopt, with modifications, the NOPR proposal to revise article 9.7.3 of the *pro forma* LGIA and article 1.5.7 of the *pro forma* SGIA to establish ride through requirements during abnormal frequency conditions and voltage conditions within the "no trip zone" defined by NERC Reliability Standard PRC-024-3 or successor mandatory ride through reliability standards, as set forth in the modified *pro forma* LGIA language discussed below. We modify the proposed requirements to acknowledge the physical limitations of newly interconnecting non-synchronous generating facilities. In the NOPR, the Commission stated that compliance with the NOPR proposal would be largely a control settings issue and may not be costly. We are persuaded by comments that contend that compliance with the NOPR proposal would be infeasible for certain types of inverters and non-synchronous generating facilities, and thus make modifications to address these concerns.

1712. Based on the record, we affirm the Commission's preliminary finding in the NOPR that the *pro forma* LGIA and *pro forma* SGIA fail to account for a non-

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[3243] EPRI Initial Comments at 21-22.

synchronous generating facility's ability to engage in momentary cessation. We note that the physical characteristics of synchronous generating facilities result in such facilities continuing to inject electric current during transmission system disturbances, consistent with the existing requirements to remain "connected to and synchronized with the [t]ransmission [s]ystem" as required by the *pro forma* LGIA and *pro forma* SGIA. As a result of these requirements, synchronous generating facilities continue to inject current during such disturbances, such that services provided supporting transmission system reliability are not disrupted during such events. However, the existing *pro forma* LGIA and *pro forma* SGIA do not currently require non-synchronous generating facilities to be capable of continuing to inject current in a manner comparable to synchronous generating facilities during system disturbances. As a result, non-synchronous generating facilities often cease injecting current during transmission system disturbances through "momentary cessation." We agree with commenters that such behavior by non-synchronous generating facilities can pose significant risk to the reliability of the bulk-power system, as documented in several reports and NERC-issued alerts.[3244]

1713. Moreover, without requirements for non-synchronous generating facilities to remain connected to and synchronized with the transmission system, and not to engage in

[3244] NERC Initial Comments at 9, 11 (citing NOPR, 179 FERC ¶ 61,194 at P 313 n.433 (citing *San Fernando Disturbance*, at vi (Nov. 2020), https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf; NERC and CAISO, *Multiple Solar PV Disturbances in CAISO* (Apr. 2022), https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf; NERC, *Odessa Disturbance* (Sept. 2021) https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf)).

momentary cessation, interconnection studies may not be able to accurately model expected behavior and identify the appropriate interconnection facilities and network upgrades to accommodate the interconnection request, resulting in an inaccurate assignment of interconnection costs. As a result, we find that the lack of comparable requirements for non-synchronous generating facilities to have the capability to remain "connected to and synchronized with the [t]ransmission [s]ystem" in the *pro forma* LGIA and *pro forma* SGIA results in rates that are unjust, unreasonable, and unduly discriminatory or preferential.

1714. While a number of commenters object to the specific provisions proposed in the NOPR to resolve this issue, addressed further below, no commenter disagrees that there is a lack of requirements in the *pro forma* LGIA and *pro forma* SGIA regarding the use of momentary cessation by non-synchronous generating facilities. Moreover, no commenter disputes the technical ability of non-synchronous generating facilities to continue to inject current during transmission system disturbances.

1715. Specifically, we require that during abnormal frequency conditions and voltage conditions within the "no trip zone" defined by NERC Reliability Standard PRC-024-3 or successor mandatory ride through reliability standards, the non-synchronous generating facility must ensure that, within any physical limitations of the generating facility, its control and protection settings are configured or set to: (1) continue active power production during disturbance and post disturbance periods at pre-disturbance levels

unless providing primary frequency response or fast frequency response;[3245] (2) minimize reductions in active power and remain within dynamic voltage and current limits, if reactive power priority mode is enabled, unless providing primary frequency response or fast frequency response; (3) not artificially limit dynamic reactive power capability during disturbances; and (4) return to pre-disturbance active power levels without artificial ramp rate limits if active power is reduced, unless providing primary frequency response or fast frequency response.

1716. In comparison to the NOPR proposal, this language, as adopted, provides non-synchronous generating facilities, within any physical limitations of the generating facility, the ability to reduce active power production in order to prioritize reactive power output in support of transmission system voltage.[3246] This language also recognizes that such facilities may not be able to ride through disturbances with the same performance as synchronous generating facilities without costly equipment modification. However, this language requires non-synchronous generating facilities, within any physical limitations of the generating facility, to configure or set their facilities to ride through disturbances

[3245] Fast frequency response is defined as power injected to (or absorbed from) the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event to improve the frequency nadir or initial rate-of-change of frequency. *See* Fast Frequency Response Concepts and Bulk Power System Reliability Needs, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf at 7.

[3246] "Active power" as used here and "real power" as used in the NOPR proposal refer to the same concept: power than can be used by load in order to perform work.

and continue to support system reliability. This language is consistent with suggestions by a number of commenters that the final rule recognize that non-synchronous generating facilities cannot provide both real and reactive power at pre-disturbance levels during a disturbance,[3247] allow for the prioritization of reactive power,[3248] and address restoration of active power output in the post-fault period.[3249]

1717. The adopted language requires non-synchronous generating facilities, within any physical limitations of the generating facility, to configure or set their facilities to be able to ride through disturbances and continuing to support system reliability. Specifically, while grid-forming inverters are available, they are not widely commercially deployed due to lack of experience, cost, or other factors.[3250] Given the existing technical capabilities of non-synchronous generating facilities, we agree with commenters that the NOPR proposal requiring active power to be maintained at pre-disturbance levels during a system disturbance in all instances may not be feasible, or preferrable from a reliability

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[3247] CAISO Initial Comments at 40; Clean Energy Associations Initial Comments at 71-72; NERC at 4; EPRI Initial Comments at 10; Invenergy Initial Comments at 58; Ørsted Initial Comments at 19-20; Public Interest Organizations Reply Comments at 14; Southern Initial Comments at 34.

[3248] Clean Energy Associations Initial Comments at 71-72; Public Interest Organizations Reply Comments at 14; Ørsted Initial Comments at 19-20.

[3249] EPRI Initial Comments at 9-10; NERC Reply Comments at 4; Clean Energy Associations Initial Comments at 76-77; Invenergy Initial Comments at 58.

[3250] A grid-forming inverter is an inverter that is capable of synthesizing voltage and frequency without an external reference. *See, e.g.*, Abraham Ellis, Grid Forming Inverters: Requirements and Practical Applications, at 4 (May 1, 2019) https://www.osti.gov/servlets/purl/1639991.

perspective. For example, we agree there may be instances where the injection of reactive power should be prioritized to maintain reliability during a system disturbance, which may require non-synchronous generating facilities to temporarily reduce their injection of active power.[3251] As a result, we adopt a modified NOPR proposal to accommodate existing technical capabilities and physical limitations of non-synchronous generating facilities, by providing for reductions in active power to prioritize reactive power while prohibiting non-synchronous generating facilities from configuring or setting their control and protection settings to effectively artificially limit such resources below their actual capability.

1718. We also adopt the NOPR proposal to revise article 9.7.3 of the *pro forma* LGIA to include in the definition of "ride through" the ability of the large generating facility to stay connected to and synchronized with the transmission system during system disturbances within under-voltage and over-voltage conditions. This revision ensures that large generating facilities are capable of remaining connected to and synchronized with the transmission system, consistent with the other ride through requirements adopted here and similar requirements in the *pro forma* SGIA.

1719. Some commenters request that the Commission either incorporate IEEE Standard 2800-2022 by reference, or explicitly incorporate this standard's performance requirements into the *pro forma* LGIA. Although we acknowledge the value of IEEE 2800-2022, we decline to incorporate it by reference. IEEE 2800-2022 was developed

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[3251] NERC Initial Comments at 23; CAISO Initial Comments at 40.

for a different purpose; it is a voluntary guideline that uses discretionary terms (e.g., "may," "should," "can," or "upon agreement"). It is unclear whether IEEE 2800-2022 would adequately address the problem identified by the Commission because the Commission would have limited authority to enforce these discretionary provisions.

1720. Invenergy and Clean Energy Associations assert that the Commission should impose similar ride through requirements on synchronous generating facilities. Alternatively, Clean Energy Associations assert that, to prevent undue discrimination, the Commission should allow ride through performance exceptions for non-synchronous generating facility trips caused by auxiliary equipment performance, which are a primary cause of ride through failure for both synchronous and non-synchronous generating facilities. We do not believe that imposing similar ride through requirements on synchronous generating facilities is necessary because the physical characteristics of synchronous generating facilities result in such facilities continuing to inject electric current during transmission system disturbances, i.e., do not allow for momentary cessation.

1721. We also decline to grant Clean Energy Associations' alternative request because we find that a ride through exception for non-synchronous generating facility trips caused by auxiliary equipment performance is not needed. As NERC has noted, protection on auxiliary equipment for non-synchronous resources, other than the generator-connected unit auxiliary transformer, is already exempted from the requirements of NERC Reliability Standard PRC-024-3 specifically because protection for such auxiliary

equipment does not cause a resource to trip or cease injecting current.[3252] We do not believe that auxiliary equipment performance is considered a physical limitation of a non-synchronous generating facility such that control and protection settings can be configured or set to reduce active power production during disturbances, and therefore no exception is needed.

1722. Pine Gate asserts that the Commission should not adopt requirements to the *pro forma* LGIP and *pro forma* SGIP that are already being addressed by NERC through the standards development process. We disagree because adding such provisions to the *pro forma* LGIA and *pro forma* SGIA will require all newly interconnecting generating facilities to abide by such provisions regardless of whether such newly interconnecting generating facilities are outside the bounds of NERC's jurisdiction. As such, we find that this modified reform can holistically address the identified issues alongside the NERC standards.

1723. NV Energy raises questions about the ramifications of non-synchronous generating facilities failing to maintain reactive power and whether the Commission is proposing any changes to reactive power compensation. We clarify that the Commission is not proposing changes to reactive power compensation in this proceeding.

1724. Invenergy argues that the Commission should not rely entirely on ride through requirements and other burdens on interconnection customers to address larger

[3252] Petition of the North American Reliability Corporation for Approval of Proposed Reliability Standard PRC-024-3, Docket No. RD20-7, at 12 (filed Mar. 20, 2020).

transmission system issues that should be addressed through regional transmission planning processes. The need to establish interconnection requirements for generating facilities to "remain connected to and synchronized with the [t]ransmission [s]ystem" during system disturbances is properly addressed in this proceeding that deals with reforming the interconnection processes for newly interconnecting generating facilities. Regarding Invenergy's arguments that larger transmission system issues need to be addressed in the regional transmission planning processes, we note that while reforms to regional transmission planning are outside the scope of this proceeding, the Commission is considering addressing regional transmission planning and cost allocation in another pending proceeding.[3253]

1725. EPRI argues that the grandfathering of existing non-synchronous generating facilities is an important consideration that should be addressed through Commission and NERC requirements and suggests that the Commission could add a procedure and criteria for a transmission provider to waive the grandfathering rule and require retrofits of existing non-synchronous generating facilities at the time of plant changes or require upgrades to meet the specified performance and modeling requirements. We decline to add the requested procedure. The final rule changes to the *pro forma* LGIA and *pro forma* SGIA adopted herein apply prospectively to interconnection customers that execute, or request the unexecuted filing of, an LGIA after the Commission-approved

[3253] *See* Transmission Planning and Cost Allocation NOPR, 179 FERC ¶ 61,028 (2022).

effective date of the transmission provider's filing in compliance with this final rule. Both the NOPR proposal and the adopted language were intended to be achieved through changes to control settings at minimal cost for current inverter technology; it did not contemplate imposing potentially significant retrofit or equipment costs on existing non-synchronous generating facilities.[3254]

1726. Ørsted requests clarification on how the NOPR proposal will affect a plant controller for wind turbines that is frozen in fault ride through mode and control actions aiding voltage recovery are performed by individual turbines until the voltage profile returns to the normal operating band of 90-110% of rated voltage. We note that the reforms, as adopted, apply to a non-synchronous generating facility as a whole, rather than to any individual component within the facility. As long as the non-synchronous generating facility as a whole meets the ride through requirements, it does not matter which part of the facility is controlling the generating facility's output.

1727. Ørsted also notes that non-synchronous generating facilities may freeze in phase locked loop during disturbances, making them not strictly synchronized with the transmission system. Ørsted asks the Commission to remove the phrase "stay synchronized" from article 9.7.3 of the *pro forma* LGIA. We decline to do so because the NOPR did not propose to revise this phrase and this final rule establishes the specific ride through requirements for newly interconnecting non-synchronous generating facilities.

[3254] NOPR, 179 FERC ¶ 61,194 at P 325.

1728. Ørsted recommends that instead of references in this clause to "good utility practice," the Commission should instead rely on Order No. 842 and its definition of "Bulk-Power System – Primary Frequency Response." This comment refers to language not subject to the Commission's proposed revisions and is therefore outside the scope of this rulemaking proceeding. We also note that "Bulk-Power System – Primary Frequency Response" refers to the title of Order No. 842, and not any definition within.

c. Applicability of Ride Through Requirements

i. Need for Reform and NOPR Proposal

1729. In the NOPR, the Commission noted that generating facilities interconnecting under the *pro forma* LGIA that are subject to reliability standards are required to ride through frequency and voltage disturbance events, while generating facilities that are not already subject to reliability standards are not, despite the fact that all generating facilities newly interconnecting under the *pro forma* LGIA are technically capable of riding through disturbances.[3255] The Commission explained that there is an existing gap in the applicability of ride through requirements for large generating facilities with a capacity above 20 MW and with a gross plant/facility aggregate nameplate rating of 75 MVA or less.[3256] The Commission preliminarily found that the *pro forma* LGIA requirements could result in unduly discriminatory or preferential treatment due to this gap in the

[3255] NOPR, 179 FERC ¶ 61,194 at P 326.

[3256] *Id.* P 340.

applicability of ride through performance requirements to similarly situated generating facilities.

1730. The Commission proposed to revise the *pro forma* LGIA to require that all newly interconnecting large generating facilities provide ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis.[3257] The Commission noted that the proposed reform is consistent with existing language in article 1.5.7 of the *pro forma* SGIA that requires newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events.

1731. In addition to the substantive changes, the Commission proposed to replace the term "applicable reliability council" with "electric reliability organization," and replace the term "control area" with "balancing authority area" throughout the *pro forma* LGIP and *pro forma* LGIA. The Commission explained that these proposed replacements reflect updated terminology.[3258]

ii. <u>Comments</u>

1732. Several commenters support the NOPR proposal.[3259] Enel notes that the Commission's proposed definition of "electric reliability organization" includes NERC,

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[3257] *Id.*

[3258] *Id.* P 341.

[3259] Ameren Initial Comments at 34; APPA-LPPC Initial Comments at 33; CAISO Initial Comments at 39-40.

but it does not include the applicable regional entity, which Enel asserts should be included because the regional entity may have approved the regional reliability standards.[3260]

iii. Commission Determination

1733. We adopt the NOPR proposal to revise the *pro forma* LGIA to require that all newly interconnecting large generating facilities provide frequency and voltage ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis. Adopting this reform enables the Commission to address an existing gap in the applicability of ride through requirements for large generating facilities with a capacity above 20 MW and with a gross plant/facility aggregate nameplate rating 75 MVA or less.

1734. Based on the record before us, we confirm the Commission's preliminary finding in the NOPR that the *pro forma* LGIP is unduly discriminatory or preferential insofar as generating facilities that are not already subject to reliability standards are not required to ride through frequency and voltage disturbance events, despite being technically capable of doing so. We note that no commenter opposes this reform.

1735. We also adopt the NOPR proposal to replace the term "applicable reliability council" with "electric reliability organization," and the term "control area" with "balancing authority area," throughout the *pro forma* LGIP and *pro forma* LGIA. In response to Enel's concerns, we note that, while regional reliability standards may be

[3260] Enel Initial Comments at 81.

developed by the applicable regional entity, the Commission has found that regional reliability standards are considered part of the electric reliability organization's set of reliability standards and are therefore covered under the proposed definition.[3261]

D. Issues Beyond the Scope of this Rulemaking

1. Comments

1736. Multiple commenters ask the Commission to consider additional information or interconnection reforms not specifically raised in the NOPR. For example, some commenters address foundational issues such as generator retirement and/or replacement processes;[3262] the application of generator interconnection standards to merchant transmission and HVDC projects;[3263] conducting a root-cause investigation of interconnection queue delays to identify and address key barriers to bringing new generating facilities online;[3264] initiating a technical conference to identify additional reforms to meet present and future challenges;[3265] establishing a process to provide access to transmission data to third-party businesses;[3266] introduction of competition into the

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[3261] Order No. 672, 114 FERC ¶ 61,104, at P 296, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328.

[3262] AEP Initial Comments at 43-44; Elevate Initial Comments at 3-7, 8-11; Illinois Commission Initial Comments at 11; New York State Department Reply Comments at 4.

[3263] Invenergy Initial Comments at 64-65.

[3264] Equinor Wind Reply Comments at 7.

[3265] Pine Gate Reply Comments at 5.

[3266] Tesla Initial Comments at 6, 8.

interconnection process or construction of network upgrades;[3267] the introduction of project prioritization to allocate scarce interconnection access;[3268] changes to operational practices to reduce network upgrade requirements;[3269] and issues particular to different regions or transmission providers.[3270]

1737. Other commenters seek changes to tariff language such as additional reforms specific to small generating facilities and the small generator interconnection process;[3271] explicitly stating that interconnection terms may be subject to remedial waiver upon appropriate Commission action;[3272] requiring detailed information be made available concerning either transmission congestion on transmission providers' systems or technical information associated with a particular point of interconnection;[3273] clarifications to the interconnection service types (i.e., energy-only or network

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[3267] Enel Initial Comments at 5, 52-56; Shell Reply Comments at 5-18.

[3268] Arizona Commission Initial Comments at 1; Colorado Commission Initial Comments at 9.

[3269] Clean Energy Associations Initial Comments at 64.

[3270] Avangrid Initial Comments at 24-25; New York State Department Initial Comments at 10; PJM Part 1 Reply Comments at 1; Roy J Shanker Initial Comments at 2-7; Roy J Shanker Reply Comments at 3-9; Southern Reply Comments at 8-9.

[3271] Bonneville Initial Comments at 25; EPRI Initial Comments at 24-38; Hydropower Commenters Initial Comments at 10-11; IREC Initial Comments at 2-3; R Street Initial Comments at 9; and Xcel Initial Comments at 19.

[3272] OSPA Reply Comments at 14.

[3273] CREA and NewSun Initial Comments at 21-22; Ørsted Initial Comments at 5-6.

resource);[3274] replacing power flow studies with security constrained economic dispatch analysis for energy-only service studies;[3275] the three-year suspension option in the *pro forma* LGIA;[3276] and additional *pro forma* LGIA language on termination and breach.[3277]

1738. Several commenters focus on process-specific reforms, such as automation of the interconnection queue process to ease delays;[3278] aligning the interconnection queue and the project development processes;[3279] interconnection study issues such as staffing to conduct studies and study criteria and scope;[3280] additional transparency from transmission providers on the interconnection study process, such as online interconnection queue tracking and performance metrics;[3281] and whether to implement

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[3274] Enel Initial Comments at 27-28; North Dakota Commission Initial Comments at 7; R Street Initial Comments at 7; Tri-State Initial Comments at 26; Xcel Initial Comments at 16.

[3275] Enel Initial Comments at 73-75.

[3276] El Paso Electric Initial Comments at 4-5.

[3277] Tri-State Initial Comments at 34-35.

[3278] CESA Initial Comments at 5; NextEra Initial Comments at 2.

[3279] Enel Initial Comments at 2-4.

[3280] Affected Interconnection Customers Initial Comments at 14-15; Clean Energy Associations Initial Comments at 27; CREA and NewSun Initial Comments at 21-22; Cypress Creek Initial Comments at 3-8; New York State Department Initial Comments at 3.

[3281] Public Interest Organizations Initial Comments at 23-25.

an independent transmission monitor or allow third parties to conduct interconnection studies to reduce interconnection queue backlogs.[3282]

1739. Some commenters focus on network upgrade cost issues, in particular the participant funding model currently in place in certain RTOs/ISOs;[3283] minimum thresholds for identifying network upgrades;[3284] a self-build option for stand-alone facilities;[3285] and the "good faith" standard applied to cost and timeline estimates for network upgrades and related transmission facilities.[3286]

1740. Commenters raising resource-specific concerns address the interconnection of qualifying facilities;[3287] challenges specific to the hydropower industry, including modifications to the readiness standard and site control requirements;[3288] steps to promote

[3282] Dominion Reply Comments at 22-24; EPSA Initial Comments at 13-14; SDG&E Reply Comments at 2; Southern Reply Comments at 6-7; ACORE Initial Comments at 5.

[3283] ACORE Initial Comments at 8; CREA and NewSun Initial Comments at 93-104; NextEra Reply Comments at 3, 16; North Carolina Commission and Staff Initial Comments at 2-16; OSPA Reply Comments at 4-7; Public Interest Organizations Reply Comments at 13-14; Senators Hickenlooper and King Initial Comments at 1-2.

[3284] Enel Initial Comments at 2-4.

[3285] CESA Initial Comments at 16-17; EEI Reply Comments at 14-15; Interwest Initial Comments at 5.

[3286] Pattern Energy Initial Comments at 14-15.

[3287] CREA and NewSun Initial Comments at 104-106; Uda Law Firm Initial Comments at 1-9.

[3288] Hydropower Commenters Initial Comments at 7.

new pumped storage projects;[3289] using regional planning to develop operating assumptions applied to the study of electric storage resources;[3290] and greater clarity on interconnection of battery storage additions to existing and proposed generating facilities.[3291]

1741. Several commenters argue in favor of greater coordination between generator interconnection and transmission planning[3292] or identify interconnection as a matter requiring interregional planning.[3293]

1742. Some comments request that the Commission provide distinct treatment for Native American energy projects by adopting rules and policies that meet the unique needs of Tribes and that allow alternative means for fulfilling interconnection requirements, such as by providing additional time for the posting of deposits or eliminating commercial

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[3289] *Id.* at 27-28.

[3290] Interwest Reply comments at 15.

[3291] SEIA Reply Comments at 21-22.

[3292] ACORE Initial Comments at 2-4; ACEG Initial Comments at 1-4; CESA Initial Comments at 13-14; Clean Energy Associations Initial Comments at 10-11; Consumer Protection Coalition Reply Comments at 1-2; Cypress Creek Initial Comments at 10-11; EDF Renewables Initial Comments at 12-13; ELCON Initial Comments at 11-13; Enel Reply Comments at 2; ENGIE Reply Comments at 4; Google Initial Comments at 6-7, 22; Invenergy Initial Comments at 62-63; Interwest Reply Comments at 15; National Grid Initial Comments at 45-46; New York State Department Reply Comments at 2-4; NYTOs Initial Comments at 23-24; OSPA Reply Comments at 15; Pattern Energy Initial Comments at 6-7; Public Interest Organizations Reply Comments at 16; R Street Initial Comments at 6-7; Union of Concerned Scientists Reply Comments at 8.

[3293] North Carolina Commission and Staff Initial Comments at 2-3; Pattern Energy Initial Comments at 8-11.

readiness requirements.[3294] Other comments request that the Commission incorporate environmental justice considerations into the interconnection process by quantifying in the proportional impact analysis the remediation of past economic injustice and benefits of renewable development in impoverished areas[3295] or by prioritizing the provision of low-cost, clean energy to low income and people of color communities under the FPA's public interest standard.[3296]

2. Commission Determination

1743. We consider the comments referenced in the section above to be beyond the scope of this proceeding. The Commission proposed specific reforms in the NOPR, to which commenters have responded and for which a record has been established. Even for those issues tangentially connected to NOPR proposals, the record here is inadequate to support their full consideration. Further, we consider issues regarding the coordination of transmission planning with generator interconnection to be beyond the scope of this rulemaking. We note that the Commission proposed reforms related to coordination between regional transmission planning and cost allocation and generator interconnection in Docket No. RM21-17-000.[3297]

[3294] OSPA Reply Comments at 15-16.

[3295] OSPA Initial Comments at 15-16; OSPA Reply Comments at 3.

[3296] Energy Keepers Initial Comments at 3; Navajo Utility Initial Comments at 13. Public Interest Organizations Reply Comments at 11.

[3297] ANOPR, 176 FERC ¶ 61,024.

IV. Compliance Procedures

A. NOPR Proposal

1744. In the NOPR, the Commission proposed to require each transmission provider to submit a compliance filing within 180 days of the effective date of the final rule revising its LGIP, LGIA, SGIP, and SGIA, as necessary, to demonstrate that it meets the requirements set forth in the final rule.[3298] The Commission also proposed to permit appropriate entities to seek an "independent entity variation" or a "regional reliability variation" from the proposed requirements.[3299] The Commission further noted that some transmission providers may have provisions in their existing LGIPs, LGIAs, SGIPs, and SGIAs subject to the Commission's jurisdiction that the Commission has previously deemed to be consistent with or superior to the *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and/or *pro forma* SGIA or permissible under the independent entity variation standard or regional reliability variation standard. Where these provisions would be modified by the final rule, the Commission proposed to require transmission providers to either comply with the final rule or demonstrate that these previously approved variations continue to meet the "consistent with or superior to" and "regional reliability variation" standard for non-RTO/ISO transmission providers and the independent entity variation standard for RTOs/ISOs.

[3298] NOPR, 179 FERC ¶ 61,194 at P 342.

[3299] *Id.* (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 822-827; Order No. 2006, 111 FERC¶61,220 at PP 546-550).

1745. The Commission explained that it would assess whether each compliance filing satisfies the proposed requirements and issue additional orders as necessary to ensure that each transmission provider meets the requirements of the final rule.[3300]

1746. The Commission also proposed that non-public utility transmission providers would have to adopt the proposed requirements as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[3301]

B. Comments

1. Compliance Filing Deadline

1747. Consumers Energy and NRECA support the proposed requirement for transmission providers to submit compliance filings within 180 days of the effective date of a final rule in this proceeding.[3302] NRECA states that 180 days is a reasonable amount of time for transmission providers to assess their generation portfolios and for interconnection customers to gauge project viability and withdraw those interconnection requests that are not commercially ready.[3303] Consumers Energy suggests that the Commission require RTOs/ISOs to justify any individual extensions for compliance

[3300] *Id.* P 343.

[3301] *Id.* P 344.

[3302] Consumers Energy Initial Comments at 10; NRECA Initial Comments at 7, 49.

[3303] NRECA Initial Comments at 7, 49.

filings.[3304] NRECA asks the Commission to waive any existing withdrawal penalties during the period between a final rule and compliance filings to encourage the rapid withdrawal of speculative interconnection requests and the pursuit of ready interconnection requests.[3305]

1748. Some commenters argue that the Commission should provide a longer time period for compliance filings because the scope and complexity of the reforms will require substantial time and resources and will involve lengthy stakeholder processes.[3306] Some commenters also note that transmission providers will need to balance other priorities while developing compliance filings, such as administering the interconnection queue and pursuing transmission planning reforms.[3307] Some commenters state that the 180-day period will be difficult for large, multi-state RTOs/ISOs that must develop large-scale tariff revisions in conjunction with large stakeholder communities.[3308] EEI suggests a

[3304] Consumers Energy Initial Comments at 10.

[3305] NRECA Initial Comments at 49.

[3306] Dominion Initial Comments at 6; EEI Initial Comments at 22; MISO Initial Comments at 126; NEPOOL Initial Comments at 12.

[3307] EEI Initial Comments at 22; MISO Initial Comments at 126.

[3308] Avangrid Initial Comments at 36-37; Dominion Initial Comments at 41-42; MISO Initial Comments at 126.

240-day deadline for compliance filings,[3309] while other commenters state that one year would be more appropriate.[3310]

1749. PJM asks the Commission to hold its compliance filing obligation in abeyance until PJM completes the transition mechanism from its recent interconnection queue reform in Docket No. ER22-2110-000, which was the result of an 18-month stakeholder process.[3311] PJM states that, if it is required to submit a compliance filing during the transition process, that will cast a cloud over the transition process while the request for an independent entity variation works through a prolonged regulatory process, bringing into doubt interconnection agreements finalized as part of the transition and further aggravating backlogs.[3312] PJM explains that, when it completes this transition process, it can evaluate whether to adopt the final rule's reforms or demonstrate that its reforms are superior.[3313] PJM asserts that such a "staged" compliance process aligns with past Commission decisions and would bring more certainty to interconnection customers.[3314]

[3309] EEI Initial Comments at 22.

[3310] Dominion Initial Comments at 6; MISO Initial Comments at 126.

[3311] PJM Initial Comments at 2-5, 11; *see also* OPSI Initial Comments at 2-3 (explaining that it will be crucial that this proceeding does not disrupt PJM's ongoing interconnection queue reform); *see also PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162.

[3312] PJM Initial Comments at 2, 5, 11.

[3313] *Id.* at 12.

[3314] *Id.* at 3 (citing, e.g., Order No. 890, 118 FERC ¶ 61,119 at P 135 (adopting a two-tiered implementation process of the final rule)).

2. Regional Flexibility

1750. A number of commenters call for the final rule to provide regional flexibility to account for differences in geography, state policies and regulatory frameworks, different network electrical characteristics, market structures, resource mixes, and other factors.[3315] Many commenters explain that many transmission providers have already adopted or are in the process of adopting some of the NOPR proposals or similar processes targeting the challenges cited in the NOPR.[3316] Many commenters ask the Commission to ensure the final rule acknowledges and accommodates existing interconnection queue reform efforts and does not undo or disrupt progress.[3317] Some commenters specifically ask the

[3315] APPA-LPPC Initial Comments at 2-3; Avangrid Initial Comments at 36; Avangrid Reply Comments at 4; Dominion Reply Comments at 4; EEI Initial Comments at 3-4; EEI Reply Comments at 13; Idaho Power Initial Comments at 1; Illinois Commission Comments at 3; Indicated PJM TOs Initial Comments at 1-2; Indicated PJM TOs Reply Comments at 43; ISO-NE Initial Comments at 3, 13, 15-16, 38; MISO TOs Initial Comments at 13; NARUC Initial Comments at 6-7; National Grid Initial Comments at 4-5; NEPOOL Initial Comments at 3-4, 12, 17; NESCOE Reply Comments at 4; NRECA Initial Comments at 7; NYTOs Initial Comments at 6; North Dakota Commission Initial Comments at 2; Southern Initial Comments at 14-15; U.S. Chamber of Commerce Initial Comments at 2-3.

[3316] ACORE Reply Comments at 6; Alliant Initial Comments at 1; Ameren Initial Comments at 35; APPA-LPPC Initial Comments at 2-3; ClearPath Initial Comments at 6; Early Adopters Coalition Initial Comments at 2, 13; EEI Initial Comments at 3-4; MISO Initial Comments at 2-3, 18; MISO Reply Comments at 2; NARUC Initial Comments at 10-11; National Grid Initial Comments at 4-5; NYISO Reply Comments at 2; NYTOs Initial Comments at 6; Omaha Public Power Initial Comments at 13; U.S. Chamber of Commerce Initial Comments at 2-3.

[3317] ACORE Reply Comments at 6; Alliant Initial Comments at 1; APPA-LPPC Initial Comments at 2-3; Ameren Initial Comments at 35; Early Adopters Coalition Initial Comments at 2-3, 13, 19, 21; Dominion Initial Comments at 42; Dominion Reply Comments at 4; Duke Southeast Utilities Initial Comments at 3-4; Illinois Commission Comments at 3; Indicated PJM TOs Initial Comments at 1-2; Indicated PJM TOs Reply

Commission to allow transmission providers like PJM and Dominion to implement recent interconnection queue reform proposals, even though they differ in some aspects from the NOPR.[3318] Some commenters ask the Commission to continue applying its current standards for variations from the *pro forma* LGIP (i.e., independent entity variations for RTOs/ISOs and consistent with or superior to variations for non-RTOs/ISOs).[3319] For example, ISO-NE contends that the Commission should respect its existing independent entity variations and allow it to continue building upon those variations.[3320]

Comments at 9; MISO Initial Comments at 4-5, 18-19, 128; MISO TOs Initial Comments at 7-9; NARUC Initial Comments at 7, 11; National Grid Initial Comments at 4-5; NRECA Initial Comments at 8; NYTOs Initial Comments at 6; Omaha Public Power Initial Comments at 13; OMS Initial Comments at 3-4; PacifiCorp Initial Comments at 2; U.S. Chamber of Commerce Initial Comments at 2-3.

[3318] ClearPath Initial Comments at 6; Dominion Initial Comments at 5-6; Indicated PJM TOs Initial Comments at 1-2; MISO Reply Comments at 2; PJM Initial Comments at 2.

[3319] Ameren Initial Comments at 35; Consumer Protection Coalition Reply Comments at 2; EEI Initial Comments at 3; Google Reply Comments at 7-8; Indicated PJM TOs Initial Comments at 9; Indicated PJM TOs Reply Comments at 44; ISO-NE Initial Comments at 13-15; National Grid Initial Comments at 4-5; NEPOOL Initial Comments at 3; NYTOs Initial Comments at 6; PG&E Initial Comments at 2; PG&E Reply Comments at 2; PJM Initial Comments at 3, 12.

[3320] ISO-NE Initial Comments at 8-15 (providing a detailed overview of ISO-NE's existing independent entity variations, which align the interconnection process with the forward capacity market, provide for targeted clustering, and allow interconnection customers to pursue elective transmission upgrades to support queued interconnection requests).

1751. In contrast, other commenters request that the Commission apply a new standard when evaluating variations from the *pro forma* requirements.[3321] OMS asks the Commission to allow transmission providers initiating their own stakeholder-supported interconnection reforms to continue developing regionally appropriate solutions upon a compliance showing of "substantial conformity" with the final rule requirements.[3322] MISO argues that the Commission should create an "independent entity presumption of reasonableness," under which the Commission would rebuttably presume that any previous, proactive RTO/ISO reform that addresses the objectives of a final rule requirement (but does not conform to every detail) is eligible for an independent entity variation, unless an intervenor demonstrates that the previous reform does not provide the benefit that technical compliance with the final rule would.[3323] NextEra also states that requiring transmission providers and stakeholders to have to justify whether their past reform initiatives match the Commission's new rule would likely waste time and resources.[3324]

1752. Similarly, the Early Adopters Coalition ask the Commission to rebuttably presume that first-ready, first-served interconnection queue reforms already in place continue to be just and reasonable and not unduly discriminatory and consistent with or superior to the

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[3321] MISO Initial Comments at 18-19.

[3322] OMS Initial Comments at 4.

[3323] MISO Initial Comments at 18-19.

[3324] NextEra Reply Comments at 7.

pro forma requirements.[3325] Further, the Early Adopters Coalition and Indicated PJM TOs argue that there is an insufficient legal foundation under FPA section 206 to conclude that the Early Adopters Coalition's tariffs are unjust, unreasonable, and unduly discriminatory or preferential because the Commission's FPA section 206 finding only speaks to the generic *pro forma* requirements, while many transmission providers' tariffs have already departed from those requirements.[3326] Indicated PJM TOs state that the Commission lacks the authority under FPA section 206 to require modification of a tariff that does not include the elements determined in the final rule to be unjust and unreasonable or unduly discriminatory.[3327]

1753. The Early Adopters Coalition also express concern that the proposed reforms would result in a higher burden of proof to justify departures from the *pro forma* requirements in future filings and signal that the Commission may not accept further incremental improvements; therefore, they ask the Commission to clarify that the final rule will not stifle their ability to improve their existing tariffs.[3328]

1754. PacifiCorp expresses concern that the NOPR proposal could disrupt some of PacifiCorp's unique processes, including its inclusion of small generating facilities in the

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[3325] Early Adopters Coalition Initial Comments at 18.

[3326] *Id.* at 2, 15 (citing *Emera Maine v. FERC*, 854 F.3d 9, 25 (D.C. Cir. 2017)); Indicated PJM TOs Reply Comments at 8; PacifiCorp Initial Comments at 6-7.

[3327] Indicated PJM TOs Reply Comments at 7-9.

[3328] Early Adopters Coalition Initial Comments at 21.

cluster study process with large generating facilities and its incorporation of the Commission-jurisdictional interconnection process into its state-level interconnection procedures.[3329]

1755. CREA and NewSun contest PacifiCorp's and the other Early Adopters Coalition's argument that the Commission's approval of their LGIPs under FPA section 205 exempts them from any reforms adopted in a final rule in this proceeding because the Commission has an obligation under FPA section 206 to remedy unjust, unreasonable, and unduly discriminatory or preferential practices.[3330] CREA and NewSun also note that neither utility- nor region-specific findings are necessary in a generic rulemaking; rather, the Commission can rely on basic economic theory and generic factual predictions.[3331] CREA and NewSun also assert that the sole authority cited by the Early Adopters Coalition, *Emera Maine v. FERC,* is inapposite, because it involved a challenge to a specific transmission owners' base return on equity, not a nationwide rulemaking.[3332]

1756. In response to requests for additional flexibility, Public Interest Organizations and Clean Energy Associations assert that transmission providers should be required to

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[3329] PacifiCorp Initial Comments at 7-9.

[3330] CREA and NewSun Reply Comments at 15-16.

[3331] *Id.* at 17-18 (citing *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 687 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1, 14 (2002); *Xcel Energy Servs. v. FERC*, 41 F.4th 548, 560-61 (D.C. Cir. 2022)).

[3332] *Id.* at 19.

demonstrate in compliance filings that their approach to a given requirement complies with the Commission's final rule.[3333]

1757. Xcel asks the Commission to state in the final rule that there is not just one just and reasonable approach to interconnection reform.[3334] Xcel requests that the Commission confirm that alternative approaches used by RTOs/ISOs that achieve the policy goals of prioritizing ready interconnection requests and increasing the speed of interconnection queue processing are consistent with and superior to the *pro forma* LGIP, instead of using the independent entity variation standard when approving those RTOs/ISOs' compliance filings. Xcel explains that its preferred approach would allow non-RTOs/ISOs to replicate processes that are working efficiently in RTOs/ISOs.

1758. ACORE expresses concern that too much flexibility would detract from the benefits of a final rule.[3335] ACORE explains that a consistent minimum set of requirements and common interconnection study methods and best practices is essential across all transmission providers.

[3333] Clean Energy Associations Reply Comments at 11; Public Interest Organizations Reply Comments at 14.

[3334] Xcel Initial Comments at 17.

[3335] ACORE Reply Comments at 6.

3. Reciprocity Tariffs

1759. APPA-LPPC and NRECA seek clarification on the NOPR's statements regarding reciprocity tariffs.[3336] They point out that Commission precedent allows non-public utilities to satisfy the reciprocity requirement of Order No. 888 through one of three means: (1) providing service to a public utility transmission provider under a safe harbor tariff; (2) providing service under a bilateral agreement; or (3) seeking waiver.[3337] APPA-LPPC and NRECA explain that the NOPR's statement that non-public utility transmission providers "will have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888" could be read to suggest that the other ways of satisfying the reciprocity requirement no longer exist.[3338] APPA-LPPC and NRECA ask the Commission to clarify that non-public utilities will still be able to satisfy reciprocity requirements through bilateral arrangements or waiver.

4. Effective Date

1760. MISO asks the Commission to make the reforms effective when orders on compliance are issued, rather than on the final rule's effective date, to avoid retroactive implementation of the proposed reforms and disruption in administering interconnection

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[3336] APPA-LPPC Initial Comments at 34-36; NRECA Initial Comments at 10, 50.

[3337] APPA-LPPC Initial Comments at 34; NRECA Initial Comments at 50.

[3338] APPA-LPPC Initial Comments at 36; NRECA Initial Comments at 51.

queues.[3339] MISO explains that an effective date prior to the date of accepted compliance provisions would require a transmission provider to file new agreements with pending language, which means that transmission providers will need to file interconnection agreements and service agreements instead of using the electronic quarterly report (EQR) process.

5. <u>Miscellaneous</u>

1761. SoCal Edison states that the final rule should not automatically apply to a wholesale distribution access tariff without further consideration in a separate rulemaking.[3340] SoCal Edison argues that the Commission should allow entities to align distribution-level tariffs with corresponding transmission-level tariffs to avoid gaming of interconnection locations and contends that the changes proposed in this NOPR are too extensive to apply to the unique characteristics of the distribution system.[3341] SoCal Edison states that the Commission has previously confirmed that reforms to the LGIP and LGIA are not required for the interconnection agreements under the wholesale distribution access tariff, and different processes, interconnection costs, and penalties could introduce new challenges for wholesale distribution providers and interconnection efficiencies that have not been addressed in the NOPR.

[3339] MISO Initial Comments at 127; MISO Reply Comments at 27.

[3340] SoCal Edison Initial Comments at 10; SoCal Edison Reply Comments at 2.

[3341] SoCal Edison Initial Comments at 10-11.

C. Commission Determination

1762. We modify the deadline for transmission providers to submit a compliance filing to adopt the requirements of this final rule as revisions to the LGIP, LGIA, SGIP, and SGIA in their tariffs. We require the submission of such compliance filings within 90 calendar days of the publication date of this final rule in the *Federal Register* rather than the proposed 180 days from the effective date of the final rule. We believe that it is important to implement this final rule in a timely manner, given the pressing need to reform the interconnection processes, as discussed in this final rule. On the Commission-approved effective date of the transmission provider's compliance filing with this final rule, the transmission provider will commence the transition study process.[3342] After the conclusion of the transition study process, the transmission provider will begin the first standard cluster study process,[3343] and in its compliance filing, the transmission provider will indicate the number of calendar days after the conclusion of the transition study process when it will begin this first standard cluster study process (e.g., 30 calendar days after the conclusion of the transition study process).[3344] By setting a 90-calendar day compliance filing deadline, the Commission may be in a position to act on the filings sooner, which will allow transmission providers to commence the transition process and

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[3342] *Pro forma* LGIP section 5.1.1.1 (Transitional Serial Study); *Pro forma* LGIP section 5.1.1.2 (Transitional Cluster Study).

[3343] We note that this standard cluster study process is distinct from the transitional cluster study process described above. *See supra* Section III.A.7.c.

[3344] *Pro forma* LGIP section 3.4.1 (Cluster Request Window).

progress to the first standard cluster study process earlier, and thereby implement the reforms contemplated by this final rule earlier rather than later.

1763. We note that 90 days is longer than the 60 days provided for compliance with Order No. 2003. In their compliance filings for Order No. 2003, transmission providers were required to adopt the *pro forma* LGIP and *pro forma* LGIA. Under this final rule, transmission providers are required to revise the LGIP, LGIA, SGIP, and SGIA in their tariffs, but are not provided significant discretion as to the terms of those documents, except for those who request deviations, as discussed below. While we recognize that the compliance filings for some transmission providers will entail more complexity, we believe that 90 calendar days should be sufficient time to prepare and submit even the more complex compliance filings. Further, the need to implement the reforms set forth in this final rule earlier rather than later outweighs the concerns raised about the timing of the compliance filing deadline.

1764. Consistent with Order Nos. 888, 890, 2003, 2006, and 845, we adopt the NOPR proposal to continue to apply the "consistent with or superior to" standard when considering proposals from non-RTO/ISO transmission providers to deviate from the requirements of this final rule.[3345] Consistent with Order Nos. 2003, 2006, and 845, we

[3345] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769-770; Order No. 890, 118 FERC ¶ 61,119 at P 109 ("[W]e reiterate that any departures from the *pro forma* [open access transmission tariff] proposed by an ISO or an RTO must be 'consistent with or superior to' the *pro forma* [open access transmission tariff] in this Final Rule."); Order No. 2003, 104 FERC ¶ 61,103 at P 825; Order No. 2006, 111 FERC ¶ 61,220 at PP 546-547; Order No. 845, 163 FERC ¶ 61,043 at P 43 (explaining that a transmission provider that is not an RTO/ISO that seeks a variation from the requirements of the final rule must present its justification for the variation as consistent

adopt the NOPR proposal to continue to use the "independent entity variation" standard when considering such proposals from RTOs/ISOs.[3346] Consistent with Order Nos. 888, 890, 2003, 2006, and 845, we adopt the NOPR proposal to continue to allow non-RTO/ISO transmission providers to use the regional differences rationale to seek variations made in response to established reliability requirements.[3347] In this final rule, we make no changes to the standards used to judge requested variations, as described in Order Nos. 888, 890, 2003, 2006, and 845.

1765. We reject requests to presume that any transmission provider's tariff meets the requirements of this final rule. We recognize that many transmission providers have adopted or are in the process of adopting similar reforms to those adopted in this final rule. We do not intend to disrupt these ongoing transition processes or stifle further innovation. On compliance, transmission providers can propose deviations from the

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with or superior to the *pro forma* LGIA or *pro forma* LGIP).

[3346] Order No. 2003, 104 FERC ¶ 61,103 at P 826 ("[w]ith respect to an RTO or ISO . . . we will allow it to seek 'independent entity variations' from the Final Rule . . . This is a balanced approach that recognizes that an RTO or ISO has different operating characteristics depending on its size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is a market participant."); Order No. 2006, 111 FERC ¶ 61,220 at PP 447, 549; Order No. 845, 163 FERC ¶ 61,043 at P 556.

[3347] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,770; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 2003, 104 FERC ¶ 61,103 at P 826 ("if on compliance a non-RTO or ISO Transmission Provider offers a variation from the Final Rule LGIP and Final Rule LGIA, and the variation is in response to established (i.e., approved by the Applicable Reliability Council) reliability requirements, then it may seek to justify its variation using the regional difference rationale."); Order No. 2006, 111 FERC ¶ 61,220 at PP 546-547; Order No. 845, 163 FERC ¶ 61,043 at P 43.

requirements adopted in this final rule – including deviations seeking to minimize interference with ongoing transition plans – and demonstrate how those deviations satisfy the standards discussed above, which the Commission will consider on a case-by-case basis.

1766. We disagree with commenters that suggest that FPA section 206 requires the Commission to make findings specific to each transmission provider's tariff in this final rule to require transmission providers to comply with the requirements of this final rule. As some commenters recognize, neither utility- nor region-specific findings are necessary in a generic rulemaking.[3348]

1767. In response to commenters that prefer regional reform over generic one-size-fits-all reform, we note that transmission providers may seek the appropriate variation on compliance provided the reason for the variation is sufficiently justified and may continue to propose solutions to interconnection issues under FPA section 205. However, given the nation-wide need for reforms to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, as well as prevent undue discrimination, we believe that a generic rulemaking is appropriate, as explained above in Section II and throughout this final rule.

1768. In the NOPR, the Commission stated that non-public utility transmission providers "will have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of

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[3348] *See Transmission Access Policy Study Grp.*, 225 F.3d at 687-88.

Order No. 888."[3349] As requested by NRECA and APPA-LPPC,[3350] we clarify that this final rule does not modify the Commission's reciprocity requirement in Order Nos. 888 and 2003.[3351] Thus, while a non-public utility's adoption of the proposed LGIP/LGIA and SGIP/SGIA changes is a condition of maintaining a safe harbor tariff,[3352] non-public utilities may still use a request for waiver or bilateral agreements to satisfy the reciprocity requirement of Order No. 888-A.[3353]

1769. With respect to MISO's comments, as explained below, this final rule is effective **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. This final rule will be effective as described above; however, the *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIP requirements in transmission providers' tariffs will not be effective until the Commission-approved

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[3349] NOPR, 179 FERC ¶ 61,194 at P 344.

[3350] APPA-LLC Initial Comments at 34-36; NRECA Initial Comments at 50-51.

[3351] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,760-761; Order No. 2003, 104 FERC ¶ 61,103 at PP 840-842.

[3352] Order No. 2003, 104 FERC ¶ 61,103 at P 842 ("A non-public utility that has a 'safe harbor' Tariff may add to its Tariff an interconnection agreement and interconnection procedures that substantially conform or are superior to the Final Rule LGIP and Final Rule LGIA if it wishes to continue to qualify for safe harbor treatment.")

[3353] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,285-86; *see also* Order No. 2003, 104 FERC ¶ 61,103 at P 841; Order No. 2003-A, 106 FERC ¶ 61,220 at P 760 (clarifying that reciprocity applies to interconnection service in a manner consistent with the reciprocity provision in the *pro forma* open access transmission tariff); Order No. 2006, 111 FERC ¶ 61,220 at P 534.

effective date of the transmission provider's filing in compliance with this final rule. In other words, interconnection customers seeking to interconnect to MISO's transmission system will not be subject to the requirements of this final rule until the Commission issues an order on MISO's compliance filing with a Commission-approved effective date for MISO's tariff revisions.

1770. In response to SoCal Edison's request for the Commission to clarify that the reforms described herein will not automatically apply to wholesale distribution access tariffs, we note that in Order No. 2003, the Commission stated that the *pro forma* LGIA and *pro forma* LGIP adopted in that final rule apply to a request to interconnect to a public utility's "distribution" facilities used to transmit electric energy in interstate commerce on behalf of a wholesale purchaser pursuant to a Commission-filed open access transmission tariff.[3354] To the extent that SoCal Edison has concerns about its specific wholesale distribution access tariff, this is a matter better suited to SoCal Edison's compliance filing.[3355]

[3354] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 804; *id.* P 803 (some lower-voltage facilities are "local distribution" facilities not under our jurisdiction, but some are used for jurisdictional service such as carrying power to a wholesale power customer for resale and are included in a public utility's open access transmission tariff (although in some instances, there is a separate open access transmission tariff rate for using them, sometimes called a wholesale distribution rate.)); Order No. 2003-A, 106 FERC ¶ 61,220 at P 733 ("We clarify that Order No. 2003 applies to all facilities subject to a Commission-approved [open access transmission tariff], regardless of how the facilities may be labeled by the Transmission Provider) (citing *N. Y. v. FERC*, 535 U.S. at 12; *Puget Sound Energy, Inc.*, 104 FERC ¶ 61,272, at PP 16-18 (2003)).

[3355] *See* Order No. 2003-A, 106 FERC ¶ 61,220 at P 734. We note, however, that the Commission has previously accepted SoCal Edison's filing, made in compliance with Order No. 2003, to implement provisions from the Commission's *pro forma* LGIA and

1771. We also note that, in addition to the modifications described above, the *pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, *pro forma* SGIP language below includes several corrections of clerical errors and other minor, clarifying edits: *see, e.g.*, *pro forma* LGIA article 8.4, *pro forma* LGIP appendix G.

V. <u>Information Collection Statement</u>

1772. The information collection requirements contained in this final rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[3356] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[3357] Respondents subject to the filing requirements of this final rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

1773. The reforms adopted in this final rule revise the Commission's standard large generator interconnection procedures and agreements (i.e., the *pro forma* LGIP and *pro forma* LGIA) and the Commission's standard small generator interconnection procedures and agreement (i.e., the *pro forma* SGIP and *pro forma* SGIA) that every public utility transmission provider is required to include in their tariff under section 35.28 of the

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pro forma LGIP into its wholesale distribution access tariff. *See S. Cal. Edison Co.*, 110 FERC ¶ 61,176 (2005).

[3356] 44 U.S.C. 3507(d).

[3357] 5 CFR 1320.11 (2022).

Commission's regulations.[3358] This final rule requires each transmission provider to amend the standard large generator interconnection procedures and agreement and the standard small generator interconnection procedures and agreement in its tariff to implement the reforms adopted in this final rule, which are intended to ensure that the generator interconnection process is just, reasonable, and not unduly discriminatory or preferential. These provisions affect the following collections of information: FERC-516, Electric Rate Schedules and Tariff Filings (Control No. 1902-0096); and FERC-516A, Standardization of Small Generator Interconnection Agreements and Procedures (Control No. 1902-0203).

1774. In the NOPR, the Commission solicited comments on: the Commission's need for this information; whether the information will have practical utility; the accuracy of the burden estimates; ways to enhance the quality, utility, and clarity of the information to be collected or retained; and any suggested methods for minimizing respondents' burden. In response to comments on the NOPR,[3359] we note that this information collection statement estimates only those burdens[3360] to generate, maintain, retain, or disclose or

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[3358] 18 CFR 35.28(f)(1) (2022).

[3359] Indicated PJM TOs state that the NOPR did not attempt to quantify the administrative burden for the transmission provider's staff to perform the tasks required by the proposed reforms, and SPP offered an estimated range of its potential costs of administering the proposed procedures. *See* Indicated PJM TOs Initial Comments at 7; SPP Initial Comments at 28; *see also* NOPR, 179 FERC ¶ 61,194 at P 358 & n.480.

[3360] "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. For further explanation of what is included in the information collection burden, refer to

provide information to or for a federal agency, and does not intend to estimate overall compliance or implementation costs for transmission providers.

1775. Summary of the Revisions to the Collection of Information due to the final rule in Docket No. RM22-14-000:

- FERC-516: This final rule revises the Commission's *pro forma* LGIP and *pro forma* LGIA (and thus requires each public utility to amend its LGIP and LGIA) to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and prevent undue discrimination. As illustrated in the table below, most reforms affect the *pro forma* LGIP and *pro forma* LGIA.

- FERC-516A: Among other requirements, this final rule amends the Commission's standard small generator interconnection procedures and agreement (i.e., the *pro forma* SGIP and *pro forma* SGIA) regarding evaluation of alternative transmission technologies, modeling required for accurate interconnection studies, and maintenance of power production during abnormal frequency conditions and certain voltage conditions.

- Title: Electric Rate Schedules and Tariff Filings (FERC-516) and Standardization of Small Generator Interconnection Agreements and Procedures (FERC-516A).

- Action: Revision of collections of information in accordance with Docket No. RM22-14-000.

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5 CFR 1320.3 (2022).

- OMB Control Nos.: 1902-0096 (FERC-516) and 1902-0203 (FERC-516A).

- Respondents: Public utility transmission providers, including RTOs/ISOs.

- Frequency of Information Collection: One time during Year 1. Multiple times during subsequent years.

- Necessity of Information: The reforms in this final rule ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and prevent undue discrimination. The reforms are intended to ensure that the generator interconnection process is just, reasonable, and not unduly discriminatory or preferential.

- Internal Review: We have reviewed the reforms that impose information collection burdens and have determined that such reforms are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.

- Public Reporting Burden: Our estimate of the number of reporting entities is based on the number of transmission providers that submitted compliance filings to the Commission in response to Order No. 845, which is the Commission's most recent rulemaking that required transmission providers to revise their generator interconnection procedures and agreements, and Order No. 881, which is the Commission's most recent major rulemaking adopting reforms to the *pro forma* tariff. As such, we estimate that 44

transmission providers, including RTOs/ISOs, will be subject to this rulemaking. The burden and cost estimates below are based on (1) the initial need for transmission providers to file revised versions of the standard interconnection procedures and agreements in Year 1 and (2) ongoing information collection activities in connection with reporting and disclosure requirements in subsequent years. For many reforms, we estimate no ongoing information collection burden because there is either no information collection aspect of the reform or the requirements would merely supplant existing ones.

1776. The Commission estimates that the final rule in Docket No. RM22-14-000 will adjust the burden and cost of FERC-516 and FERC-516A as follows:

Table 1: Information Collection Requirements

Changes Due to Final Rule in Docket No. RM22-14-000					
Reforms	**Number of Respondents (1)**	**Annual Number of Responses Per Respondent (2)**	**Total Number of Responses (Rounded) (1) * (2) = (3)**	**Average Burden (Hr.) & Cost ($) Per Response[3361] (4)**	**Total Annual Burden Hours & Total Annual Cost ($) (Rounded) (3) * (4) = (5)**
FERC-516:					
Interconnection Information Access	44 (TPs)	Year 1: 1 Ongoing: 2	Year 1: 44 Ongoing: 88	Year 1: 4 hr; $364 Ongoing: 4 hr; $364	Year 1: 176 hr; $16,016 Ongoing: 352 hr; $32,032
First Ready, First Served Cluster Study Process	44 (TPs)	Year 1: 1 Ongoing: 4	Year 1: 44 Ongoing: 176	Year 1: 80 hr; $7,280 Ongoing: 4 hr; $364	Year 1: 3,520 hr; $320,320 Ongoing: 704 hr; $64,064

[3361] Commission staff estimate that respondents' hourly wages plus benefits are comparable to those of FERC employees. Therefore, the hourly cost used in this analysis is $91 per hour ($188,922 per year).

Changes Due to Final Rule in Docket No. RM22-14-000					
Reforms	**Number of Respondents (1)**	**Annual Number of Responses Per Respondent (2)**	**Total Number of Responses (Rounded) (1) * (2) = (3)**	**Average Burden (Hr.) & Cost ($) Per Response[3361] (4)**	**Total Annual Burden Hours & Total Annual Cost ($) (Rounded) (3) * (4) = (5)**
Allocation of Cluster Study Costs	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Allocation of Cluster Network Upgrade Costs	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Study Deposits and LGIA Deposit	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Demonstration of Site Control	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0
Commercial Readiness	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Withdrawal Penalties	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Transition Process	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0

Changes Due to Final Rule in Docket No. RM22-14-000					
Reforms	**Number of Respondents (1)**	**Annual Number of Responses Per Respondent (2)**	**Total Number of Responses (Rounded) (1) * (2) = (3)**	**Average Burden (Hr.) & Cost ($) Per Response[3361] (4)**	**Total Annual Burden Hours & Total Annual Cost ($) (Rounded) (3) * (4) = (5)**
Elimination of Reasonable Efforts Standard[3362]	44 (TPs)	Year 1: 1 Ongoing: 4	Year 1: 44 Ongoing: 176	Year 1: 80 hr; $7,280 Ongoing: 4 hr; $364	Year 1: 3,520 hr; $320,320 Ongoing: 704 hr; $64,064
Affected System Study Process	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 44	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0
Affected System *Pro Forma* Agreements	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Affected System Modeling and Study Assumptions	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Co-Located Generating Facilities Behind One Point of Interconnection with Shared Interconnection Requests	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0

[3362] Commission staff only estimates the information collection burden associated with the requirements outlined in the final rule and does not estimate the potential appeal process burden, which an applicant can pursue voluntarily.

Changes Due to Final Rule in Docket No. RM22-14-000					
Reforms	**Number of Respondents (1)**	**Annual Number of Responses Per Respondent (2)**	**Total Number of Responses (Rounded) (1) * (2) = (3)**	**Average Burden (Hr.) & Cost ($) Per Response[3361] (4)**	**Total Annual Burden Hours & Total Annual Cost ($) (Rounded) (3) * (4) = (5)**
Revisions to Modification to Require Consideration of Generating Facility Additions	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0
Availability of Surplus Interconnection Service	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Operating Assumptions for Interconnection Studies	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0
Incorporating Enumerated Alternative Transmission Technologies into the Generator Interconnection Process	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0
Modeling Requirements	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Ride-Through Requirements	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Applicability of Ride-Through Requirements	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0

Changes Due to Final Rule in Docket No. RM22-14-000					
Reforms	**Number of Respondents (1)**	**Annual Number of Responses Per Respondent (2)**	**Total Number of Responses (Rounded) (1) * (2) = (3)**	**Average Burden (Hr.) & Cost ($) Per Response[3361] (4)**	**Total Annual Burden Hours & Total Annual Cost ($) (Rounded) (3) * (4) = (5)**
Total New Burden for FERC-516 (due to Docket No. RM22-14-000)			**Year 1: 924 Ongoing: 484**		**Year 1: 30,448 hr; $2,770,768 Ongoing: 1,760 hr; $160,160**
FERC- 516A					
Incorporating Enumerated Alternative Transmission Technologies into the Generator Interconnection Process	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 80 hr; $7,280 Ongoing: 0	Year 1: 3,520 hr; $320,320 Ongoing: 0
Modeling Requirements	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Ride-Through Requirements	44 (TPs)	Year 1: 1 Ongoing: 0	Year 1: 44 Ongoing: 0	Year 1: 4 hr; $364 Ongoing: 0	Year 1: 176 hr; $16,016 Ongoing: 0
Total New Burden for FERC-516A (due to Docket No. RM22-14-000)			**Year 1: 132 responses Ongoing: 0**		**Year 1: 3,872 hr; $352,352 Ongoing: 0**
Grand Total (FERC-516 plus FERC-516A, including all respondents)			**Year 1: 1,056 Ongoing: 484**		**Year 1: 34,320 hr; $3,123,120 Ongoing: 1,760 hr; $160,160**

Changes Due to Final Rule in Docket No. RM22-14-000					
Reforms	**Number of Respondents (1)**	**Annual Number of Responses Per Respondent (2)**	**Total Number of Responses (Rounded) (1) * (2) = (3)**	**Average Burden (Hr.) & Cost ($) Per Response[3361] (4)**	**Total Annual Burden Hours & Total Annual Cost ($) (Rounded) (3) * (4) = (5)**
Grand Total Average Per Entity Cost (44 TPs)					**Year 1: $70,980 Ongoing: $3,640**

1777. In this final rule, after accounting for the adjustments and inputs noted above, updated labor costs, and reforms not being adopted, the Commission used the numbers provided in the NOPR for all reforms being adopted.

1778. Interested persons may obtain information on the reporting requirements by contacting Ellen Brown, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 via email (DataClearance@ferc.gov) or telephone ((202) 502-8663).

VI. Environmental Analysis

1779. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[3363] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final rule under

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[3363] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

§ 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classification, and services.[3364]

VII. Regulatory Flexibility Act

1780. The Regulatory Flexibility Act of 1980[3365] requires a description and analysis of proposed and final rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,[3366] transmission providers and RTOs/ISOs fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), that has a size threshold of under 950 employees (including the entity and its associates).[3367]

[3364] 18 CFR 380.4(a)(15) (2022).

[3365] 5 U.S.C. 601-612.

[3366] 13 CFR 121.201 (2022).

[3367] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. The Small Business Administration's regulations define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 950 employees ("the maximum allowed for a concern and its affiliates to be considered small"). *See* 13 CFR 121.201 (2022); *see also* 5 U.S.C. 601(3) (citing to Section 3 of the Small Business Act, 15 U.S.C. 632).

1781. We estimate that there are 44 transmission providers affected by the reforms proposed in this final rule. Furthermore, we estimate that 6 of the 44 total transmission providers, approximately 14% (rounded), are small entities.

1782. We estimate that one-time costs (in Year 1) associated with the reforms required by this final rule for one transmission provider (as shown in the table above) would be $70,980. Following Year 1, we estimate that the annual ongoing costs for one transmission provider would be $3,640. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[3368] We do not consider the estimated cost to be a significant economic impact. As a result, we certify that the reforms proposed in this final rule would not have a significant economic impact on a substantial number of small entities.

VIII. Document Availability

1783. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov).

[3368] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (Aug. 2017), https://cdn.advocacy.sba.gov/wp-content/uploads/2019/06/21110349/How-to-Comply-with-the-RFA.pdf.

1784. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number in the docket number field. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

IX. Effective Date and Congressional Notification

1785. The final rule is effective **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Danly is concurring with a separate statement attached.
Commissioner Clements is concurring with a separate statement attached.
Commissioner Christie is concurring with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

Part 35 – FILING OF RATE SCHEDULES AND TARIFFS

The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

Amend § 35.28 as follows:

a. Add a new paragraph (f)(1)(ii)

§ 35.28 **Non-discriminatory open access tariff.**

* * * * *

(f) *Standard generator interconnection procedures and agreements*.

(1) * * *

(ii) Any public utility that conducts interconnection studies shall be liable for and eligible to appeal certain penalties under the interconnection procedures and agreements adopted by the Commission-approved independent system operator or regional transmission organization under paragraph (f)(1) of this section following that public utility's failure to complete an interconnection study by the appropriate deadline.

NOTE: The following appendices will not appear in the Code of Federal Regulations.

Appendix A: Abbreviated Names of Commenters

Americans for a Clean Energy Grid	ACEG
Alliance for Clean Energy-New York	ACE-NY
American Council on Renewable Energy	ACORE
Associated Electric Cooperative, Inc.	AECI
Advanced Energy Economy	AEE
American Electric Power Service Corporation	AEP
AES Clean Energy Development, LLC	AES
Acciona Energy USA Global LLC; Copenhagen Infrastructure IV K/S; Hecate Energy LLC; Leeward Renewable Energy Development, LLC; and Tri Global Energy, LLC	Affected Interconnection Customers
Allen Meyer	Allen Meyer
Alliant Energy Corporate Services, Inc.	Alliant Energy
Amazon Energy LLC	Amazon
Ameren Services Company	Ameren
Ampjack Industries Ltd	Ampjack
Anbaric Development Partners, LLC	Anbaric
American Public Power Association and Large Public Power Council	APPA-LPPC
Apple Inc.	Apple
Arizona Public Service Company	APS
Arizona Corporation Commission	Arizona Commission
Avangrid, Inc.	Avangrid
Bonneville Power Administration	Bonneville
Bretton C Little	Bretton C Little

California Independent System Operator Corporation	CAISO
California Energy Storage Alliance	CESA
The American Clean Power Association and RENEW Northeast	Clean Energy Associations
Clean Energy Buyers Association	Clean Energy Buyers
Clean Energy States Alliance	Clean Energy States
ClearPath, Inc.	ClearPath
Colorado Public Utilities Commission	Colorado Commission
Interconnection Cost Consumer Protection Coalition	Consumer Protection Coalition
Consumers Energy Company	Consumers Energy
Community Renewable Energy Association and NewSun Energy LLC	CREA and NewSun
CTC Global Corporation	CTC Global
Cypress Creek Renewables, LLC	Cypress Creek
Dominion Energy Services, Inc	Dominion
Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; and Duke Energy Florida, LLC	Duke Southeast Utilities
Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Dominion Energy South Carolina Inc.; PacifiCorp; Public Service Company of Colorado; and Tri-State Generation and Transmission Association, Inc.	Early Adopters Coalition
Environmental Defense Fund	Environmental Defense Fund
EDF Renewables LLC	EDF Renewables
Edison Electric Institute	EEI
El Paso Electric Company	El Paso Electric
Electricity Consumers Resource Council	ELCON

Elevate Renewable Energy F7, LLC	Elevate
North American Electric Reliability Corporation; Midwest Reliability Organization; Northeast Power Coordinating Council, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation; Texas Reliability Entity, Inc.; and Western Electricity Coordinating Council	NERC
Enel North America, Inc.	Enel
Energy Keepers, Inc.	Energy Keepers
ENGIE North America, Inc.	ENGIE
Electric Power Research Institute	EPRI
Electric Power Supply Association	EPSA
Equinor Wind US LLC	Equinor Wind
Evergreen Action	Evergreen Action
Eversource Energy Service Company	Eversource
Fervo Energy Company	Fervo Energy
Golden State Clean Energy	GCSE
Google LLC	Google
Guzman Energy LLC	Guzman Energy
Hannon Armstrong Sustainable Infrastructure Capital, Inc.	Hannon Armstrong
Rye Development, LLC; rPlus Hydro, LLP; Nelson Energy LLC; Advanced Hydro Solutions LLC; Hydro Green Energy, LLC; Natel Energy, Inc.; and Sorenson Engineering, Inc. and its affiliates, Cat Creek Energy, LLC and National Hydropower Association	Hydropower Commenters
Idaho Power Company	Idaho Power
Illinois Commerce Commission	Illinois Commission
Citizens Utility Board of Illinois	Illinois CUB
Indicated PJM Transmission Owners	Indicated PJM TOs
4,293 people collected Evergreen Action	Individual Signatories

Interwest Energy Alliance	Interwest
Invenergy Solar Development North America LLC; Invenergy Thermal Development LLC; Invenergy Wind Development North America LLC; and Invenergy Transmission LLC	Invenergy
Iowa Utilities Board	Iowa Commission
Interstate Renewable Energy Council	IREC
ISO New England Inc.	ISO-NE
ISO/RTO Council	ISO/RTO Council
Los Angeles Department of Water and Power	LADWP
Longroad Energy Holdings, LLC	Longroad Energy
Lori Ecker	Lori Ecker
Microgrid Resources Coalition	Microgrid Resources
Midcontinent Independent System Operator, Inc.	MISO
MISO Transmission Owners	MISO TOs
National Association of Regulatory Utility Commissioners	NARUC
National Grid Plc	National Grid
New England Power Pool Participants Committee	NEPOOL
New England States Committee on Electricity	NESCOE
New Jersey Board of Public Utilities	New Jersey Commission
New York State Department of State Utility Intervention Unit	New York State Department
NextEra Energy, Inc	NextEra
North Carolina Utilities Commission and North Carolina Utilities Commission Public Staff	North Carolina Commission and Staff
North Dakota Public Service Commission	North Dakota Commission

Northwest & Intermountain Power Producers Coalition	Northwest and Intermountain
National Rural Electric Cooperative Association	NRECA
Navajo Tribal Utility Authority	Navajo Utility
Nevada Power Company and Sierra Pacific Power Company	NV Energy
New York Public Service Commission and New York State Energy Research and Development Authority	NY Commission and NYSERDA
New York Transmission Owners	NYTOs
New York Independent System Operator, Inc.	NYISO
Public Commission of Ohio's Office of the Federal Energy Advocate	Ohio Commission Consumer Advocate
Omaha Public Power District	Omaha Public Power
Organization of MISO States, Inc.	OMS
Ørsted North America, Inc.	Ørsted
OCETI Sakowin Power Authority	OSPA
Renewable Northwest and NW Energy Coalition	Pacific Northwest Organizations
Avista Corporation; Idaho Power Company; Portland General Electric Company; and Puget Sound Energy, Inc.	Pacific Northwest Utilities
PacifiCorp	PacifiCorp
Pattern Energy Group LP	Pattern Energy
Payton Alaama	Payton Alaama
Pennsylvania Public Utility Commission	Pennsylvania Commission
Pacific Gas and Electric Company	PG&E
Pine Gate Renewables, LLC	Pine Gate
PJM Interconnection, L.L.C.	PJM

PJM Cities and Communities Coalition	PJM Coalition
Organization of PJM States, Inc.	OPSI
PPL Electric Utilities Corporation	PPL
Puget Sound Energy, Inc.	Puget Sound
Sustainable FERC Project, Sierra Club, Natural Resources Defense Council, Earthjustice, Acadia Center, Environmental Defense Fund, National Audubon Society, Southern Environmental Law Center, and Southface	Public Interest Organizations
R Street Institute	R Street
Rick K. Lathrop	Rick K Lathrop
Roy J Shanker Ph.D.	Roy J Shanker
rPlus Hydro, LLLP	rPlus
RWE Renewables Americas, LLC	RWE Renewables
San Diego Gas & Electric Company	SDG&E
Solar Energy Industries Association	SEIA
U.S. Senators John D. Hickenlooper and Angus King	Senators Hickenlooper and King
Shell Energy North America	Shell
Southern California Edison Company	SoCal Edison
Southern Company Services, Inc.	Southern
Southwest Power Pool, Inc.	SPP
Connecticut Department of Energy and Environmental Protection, Connecticut Attorney General, Connecticut Office of Consumer Counsel, Delaware Attorney General, Delaware Division of the Public Advocate, Attorney General for the District of Columbia, District of Columbia Office of People's Counsel, Attorney General of Maryland, Maryland Office of People's Counsel, Massachusetts Attorney General, Pennsylvania Office of Consumer Advocate, and the Rhode Island Attorney General	State Agencies

Sue Hilton	Sue Hilton
Transmission Access Policy Study Group	TAPS
Tesla, Inc.	Tesla
Tri-State Generation and Transmission Association, Inc.	Tri-State
Uda Law Firm, P.C.	Uda Law Firm
Utah Municipal Power Agency	UMPA
Union of Concerned Scientists	Union of Concerned Scientists
US Chamber of Commerce	U.S. Chamber of Commerce
United States Department of Energy	U.S. DOE
VEIR Inc.	VEIR
Vermont Electric Power Company, Inc.	Vermont Electric and Vermont Transco
Vistra Corp.	Vistra
Western Area Power Administration	WAPA
WATT Coalition	WATT Coalition
Colorado Public Utilities Commission Chair Megan Decker, Oregon Public Utility Commission Chair Cynthia Hall, New Mexico Public Regulation Commission Chair Cynthia Hall and Vice-Chair Joe Maestas, Arizona Corporation Commission Chair Lea Marquez Peterson, Nevada Public Utilities Commission Chair Hayley Williamson, California Public Utilities Commission Commissioner Cliff Rechtschaffen, and Washington Utilities and Transportation Commission Commissioner Ann Rendahl	Western Regulators
WIRES	WIRES
Xcel Energy Services Inc.	Xcel

Appendix B: Interconnection Study Metrics

Table 2: RTOs/ISOs Interconnection Study Metrics 2022[1]

Transmission Provider	Completed Studies	Studies Completed Past Deadline	Delayed Studies at End of Year	Withdrawals	Withdrawn Pre-Study
CAISO	340	340	-	108	1
ISO-NE	51	46	23	24	8
MISO	609	597	285	49	0
NYISO	84	72	25	34	28
PJM[2]	153	152	2,211	240	137

[1] We do not include data from SPP in this table. SPP is transitioning to a new interconnection study process and thus its data is not clearly comparable to the other RTOs/ISOs.

[2] Data drawn from the following sources, respectively: http://www.caiso.com/Documents/FERC845_InterconnectionStudyStatistics.pdf (CAISO); https://cdn.misoenergy.org/MISO%20Generator%20Interconnection%20Study%20Metrics%20Q1%202023444684.pdf (MISO); https://www.oasis.oati.com/isne/ (ISO-NE) https://www.nyiso.com/interconnections (NYISO); and https://www.pjm.com/-/media/planning/services-requests/interconnection-study-statistics.ashx (PJM).

Table 3: Non-RTOs/ISOs Interconnection Study Metrics 2022[3]

Transmission Provider	Completed Studies	Completed Past Deadline	Delayed Studies at End of Year	Withdrawals	Withdrawn Pre-Study
Alabama Power Company (Southern Company)	148	0	0	45	5
Arizona Public Service	40	40	106	12	5
Avista Corp.	14	5	1	11	3
Black Hills Colorado	4	0	5	0	0
Black Hills Power	7	1	4	1	0
Cheyenne Light, Fuel, and Power Co.	4	0	2	0	0
Deseret Generation and Transmission Coop.	4	0	0	0	0
Dominion Energy South Carolina	2	2	0	23	21
Duke Energy Carolinas	1	1	0	4	0
El Paso Electric Co.	6	2	0	7	1
Florida Power & Light	60	43	78	0	0
GridLiance	1	0	0	0	0
Idaho Power	98	20	7	15	5
Louisville Gas and Electric	18	16	15	2	1

[3] This table excludes the following non-RTO/ISO transmission providers that did not report any completed or ongoing interconnection studies for 2022: Basin Electric Power Coop.; Cube Yadkin Transmission, LLC; Golden Spread Coop; Gulf Power Company; MATL LLP; UNS Electric, Inc.; and Versant Power.

Transmission Provider	Completed Studies	Completed Past Deadline	Delayed Studies at End of Year	Withdrawals	Withdrawn Pre-Study
Nevada Power	103	0	0	15	4
Northwestern Corp (Montana)	33	14	4	10	2
PacifiCorp	202	0	0	41	7
Portland General Electric Company	10	9	9	0	0
Public Service Company of Colorado	41	39	28	12	1
Public Service Company of New Mexico	21	21	29	8	0
Puget Sound Energy	50	37	6	6	2
Tampa Electric Company	25	13	1	4	2
Tri-State Generation and Transmission	30	0	0	11	10
Tucson Electric Power Co.[4]	20	20	0	3	2

[4] Data drawn from the following sources, respectively: https://www.oasis.oati.com/SOCO/index.html (Alabama Power Company (Southern Company)); https://www.oasis.oati.com/azps/ (Arizona Public Service); https://www.oasis.oati.com/avat/ (Avista Corp.); https://www.blackhillscorp.com/utilities-businesses/transmission/electric-transmission-services (Black Hills Colorado); https://www.blackhillscorp.com/utilities-businesses/transmission/electric-transmission-services (Black Hills Power); http://www.oatioasis.com/CLPT/index.html (Cheyenne Light, Fuel, and Power Co.); https://www.oasis.oati.com/dgt/index.html (Deseret Generation and Transmission Coop.); https://www.oasis.oati.com/SCEG/ (Dominion Energy South Carolina); http://www.oasis.oati.com/duk/index.html (Duke Energy Carolinas); https://www.oasis.oati.com/epe/index.html (El Paso Electric Co.); https://www.oasis.oati.com/FPL/index.html (Florida Power & Light); https://www.oasis.oati.com/SMCN/index.html (GridLiance);

Table 4: RTO/ISO End of Year Delayed Interconnection Studies[5]

Transmission Provider	Delayed Studies at End of 2020	Delayed Studies at End of 2021	Delayed Studies at End of 2022
CAISO	-	-	-
ISO-NE	12	19	23
MISO	479	385	285
NYISO	26	48	25
PJM	272	1,281	2,211

https://www.oasis.oati.com/ipco/ (Idaho Power); https://www.oasis.oati.com/LGEE/index.html (Louisville Gas and Electric);http://www.oasis.oati.com/NEVP/ (Nevada Power); http://www.oatioasis.com/NWMT/ (Northwestern Corp (Montana); https://www.oasis.oati.com/PPW/ (PacifiCorp); https://www.oasis.oati.com/PGE/ (Portland General Electric Company); https://www.oasis.oati.com/psco/index.html (Public Service Company of Colorado); https://www.oasis.oati.com/PNM/ (Public Service Company of New Mexico); https://www.oasis.oati.com/psei/index.html (Puget Sound Energy); https://www.oasis.oati.com/TEC/ (Tampa Electric Company); https://www.oasis.oati.com/tsgt/index.html (Tri-State Generation and Transmission); and https://www.oasis.oati.com/tepc/ (Tucson Electric Power Co.).

[5] We do not include data from SPP in this table. SPP is transitioning to a new interconnection study process and thus its data is not clearly comparable to the other RTOs/ISOs.

Table 5: Non-RTO/ISO End of Year Delayed Interconnection Studies

Transmission Provider	Delayed Studies at End of 2020	Delayed Studies at End of 2021	Delayed Studies at End of 2022
Alabama Power Company (Southern Company)	0	0	0
Arizona Public Service	29	55	106
Avista Corp.	2	7	1
Black Hills Colorado	0	0	5
Black Hills Power	0	0	4
Cheyenne Light, Fuel, and Power Co.	0	0	2
Deseret Generation and Transmission Coop.	0	0	0
Dominion Energy South Carolina	16	19	0
Duke Energy Carolinas	6	1	0
El Paso Electric Co.	1	0	0
Florida Power & Light	48	21	78
GridLiance	0	0	0
Gulf Power Co.	13	12	-
Idaho Power	0	0	7
Louisville Gas and Electric	3	12	15
Nevada Power	0	0	0
Northwestern Corp (Montana)	2	1	4
PacifiCorp	0	0	0
Portland General Electric Company	2	0	9

Transmission Provider	Delayed Studies at End of 2020	Delayed Studies at End of 2021	Delayed Studies at End of 2022
Public Service Company of Colorado	0	0	28
Public Service Company of New Mexico	20	17	29
Puget Sound Energy	0	2	6
Tampa Electric Company	16	5	1
Tri-State Generation and Transmission	28	0	0
Tucson Electric Power Co.	2	1	0

Appendix C: *Pro forma* LGIP

Note: Deletions are in brackets and additions are in italics.

Section 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than [the]Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Facilities Construction Agreement *shall mean the agreement contained in Appendix 11 to this LGIP that is made between Transmission Provider and Affected System Interconnection Customer to facilitate the construction of and to set forth cost responsibility for necessary Affected System Network Upgrades on Transmission Provider's Transmission System.*

Affected System Interconnection Customer *shall mean any entity that submits an interconnection request for a generating facility to a transmission system other than Transmission Provider's Transmission System that may cause the need for Affected System Network Upgrades on the Transmission Provider's Transmission System.*

Affected System Network Upgrades *shall mean the additions, modifications, and upgrades to Transmission Provider's Transmission System required to accommodate Affected System Interconnection Customer's proposed interconnection to a transmission system other than Transmission Provider's Transmission System.*

Affected System Operator shall mean the entity that operates an Affected System.

Affected System Queue Position *shall mean the queue position of an Affected System Interconnection Customer in Transmission Provider's interconnection queue relative to Transmission Provider's Interconnection Customers' Queue Positions.*

Affected System Study *shall mean the evaluation of Affected System Interconnection Customers' proposed interconnection(s) to a transmission system other than Transmission Provider's Transmission System that have an impact on Transmission Provider's Transmission System, as described in Section 9 of this LGIP.*

Affected System Study Agreement *shall mean the agreement contained in Appendix 9 to this LGIP that is made between Transmission Provider and Affected System Interconnection Customer to conduct an Affected System Study pursuant to Section 9 of this LGIP.*

Affected System Study Report *shall mean the report issued following completion of an Affected System Study pursuant to Section 9.6 of this LGIP.*

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

[**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.]

Applicable Reliability Standards shall mean the requirements and guidelines of [NERC,]the [Applicable Reliability Council]*Electric Reliability Organization* and the [Control Area]*Balancing Authority Area* of the Transmission System to which the Generating Facility is directly interconnected.

Balancing Authority *shall mean an entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.*

Balancing Authority Area *shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.*

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by [the] Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Cluster *shall mean a group of one or more Interconnection Requests that are studied together for the purpose of conducting a Cluster Study.*

Cluster Request Window *shall mean the time period set forth in Section 3.4.1 of this LGIP.*

Cluster Restudy *shall mean a restudy of a Cluster Study conducted pursuant to Section 7.5 of this LGIP.*

Cluster Restudy Report Meeting *shall mean the meeting held to discuss the results of a Cluster Restudy pursuant to Section 7.5 of this LGIP.*

Cluster Restudy Report *shall mean the report issued following completion of a Cluster Restudy pursuant to Section 7.5 of this LGIP.*

Cluster Study *shall mean the evaluation of one or more Interconnection Requests within a Cluster as described in Section 7 of this LGIP.*

Cluster Study Agreement *shall mean the agreement contained in Appendix 2 to this LGIP for conducting the Cluster Study.*

Cluster Study Process *shall mean the following processes, conducted in sequence: the Cluster Request Window; the Customer Engagement Window and Scoping Meetings therein; the Cluster Study; any needed Cluster Restudies; and the Interconnection Facilities Study.*

Cluster Study Report *shall mean the report issued following completion of a Cluster Study pursuant to Section 7 of this LGIP.*

Cluster Study Report Meeting *shall mean the meeting held to discuss the results of a Cluster Study pursuant to Section 7 of this LGIP.*

Clustering shall mean the process whereby *one or more* [a group of] Interconnection Requests [is]*are* studied together, instead of serially, [for the purpose of conducting the Interconnection System Impact Study]*as described in Section 7 of this LGIP.*

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Commercial Readiness Deposit *shall mean a deposit paid as set forth in Sections 3.4.2, 7.5, and 8.1 of this LGIP.*

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for [Re-Studies] *restudies* of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

[**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council.]

Customer Engagement Window *shall mean the time period set forth in Section 3.4.5 of this LGIP.*

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly

from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Electric Reliability Organization *shall mean the North American Electric Reliability Corporation or its successor organization.*

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's [device]*device(s)* for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include [the]Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility [and] *or* the aggregate net capacity of the Generating Facility where it includes [multiple energy production devices] *more than one device for the production and/or storage for later injection of electricity*.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to [the] Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean [the]Transmission Provider's Interconnection Facilities and [the]Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to [the]Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by [the]Transmission Provider or a third party consultant for [the]Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the [Interconnection System Impact]*Cluster Study*), the cost of those facilities, and the time required to interconnect the Generating Facility with[the]

Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of *this LGIP*[the Standard Large Generator Interconnection Procedures].

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix *3*[4] of *this LGIP* [the Standard Large Generator Interconnection Procedures] for conducting the Interconnection Facilities Study.

Interconnection Facilities Study Report *shall mean the report issued following completion of an Interconnection Facilities Study pursuant to Section 8 of this LGIP.*

[**Interconnection Feasibility Study** shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.]

[**Interconnection Feasibility Study Agreement** shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.]

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to *this LGIP* [the Standard Large Generator Interconnection Procedures], in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: [the Interconnection Feasibility Study, the Interconnection System Impact Study,] *the Cluster Study, the Cluster Restudy, the Surplus Interconnection Service System Impact Study*, and the Interconnection Facilities Study, described in *this LGIP* [the Standard Large Generator Interconnection Procedures].

[**Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were

interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.]

[**Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.]

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

LGIA Deposit *shall mean the deposit Interconnection Customer submits when returning the executed LGIA, or within 10 Business Days of requesting that the LGIA be filed unexecuted at the Commission, in accordance with Section 11.3 of this LGIP.*

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the [indemnifying] *Indemnifying* Party, except in cases of gross negligence or intentional wrongdoing by the [indemnifying]*Indemnifying* Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a*n equal or* later *Queue Position*[queue priority date].

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Multiparty Affected System Facilities Construction Agreement *shall mean the agreement contained in Appendix 12 to this LGIP that is made among Transmission Provider and multiple Affected System Interconnection Customers to facilitate the*

construction of and to set forth cost responsibility for necessary Affected System Network Upgrades on Transmission Provider's Transmission System.

Multiparty Affected System Study Agreement *shall mean the agreement contained in Appendix 10 to this LGIP that is made among Transmission Provider and multiple Affected System Interconnection Customers to conduct an Affected System Study pursuant to Section 9 of this LGIP.*

[NERC shall mean the North American Electric Reliability Council or its successor organization.]

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix *4*[5] of *this LGIP* [the Standard Large Generator Interconnection Procedures] for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Permissible Technological Advancement {Transmission Provider inserts definition here.}

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Proportional Impact Method *shall mean a technical analysis conducted by Transmission Provider to determine the degree to which each Generating Facility in the Cluster Study contributes to the need for a specific System Network Upgrade.*

Provisional Interconnection Service shall mean Interconnection Service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff.

Provisional Large Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between Transmission Provider and/or the Transmission Owner and the Interconnection Customer. This agreement shall take the form of the Large Generator Interconnection Agreement, modified for provisional purposes.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, [that is] established *pursuant to Section 4.1 of this LGIP.* [based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.]

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of [the]Interconnection Customer*(s)* and Transmission Provider conducted for the purpose of discussing *the proposed Interconnection Request and any* alternative interconnection options, [to]exchang[e]*ing* information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, *refining information and models provided by Interconnection Customer(s), discussing the Cluster Study materials posted to OASIS pursuant to Section 3.5 of this LGIP, and* [to]analyz[e]*ing* such information[, and to determine the potential feasible Points of Interconnection].

Site Control shall mean [documentation reasonably demonstrating]*the exclusive land right to develop, construct, operate, and maintain the Generating Facility over the term of expected operation of the Generating Facility. Site Control may be demonstrated by documentation establishing:* (1) ownership of, a leasehold interest in, or a right to develop a site [for the purpose of constructing]*of sufficient size to construct and operate* the Generating Facility*;* (2) an option to purchase or acquire a leasehold site *of sufficient size to construct and operate the Generating Facility*[for such purpose]; or (3) [an exclusivity or other business relationship between]*any other documentation that clearly demonstrates the right of Interconnection Customer*[and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or]to exclusively occupy a site [for such purpose.]*of sufficient size to construct and operate the Generating Facility. Transmission Provider will maintain acreage requirements for each Generating Facility type on its OASIS or public website.*

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction *and the following conditions are met: (1) a Substation Network Upgrade must only be required for a single Interconnection Customer in the Cluster and no other Interconnection Customer in that Cluster is required to interconnect to the same Substation Network Upgrades, and (2) a System Network Upgrade must only be required for a single Interconnection Customer in the Cluster, as indicated under the Transmission Provider's Proportional Impact Method*. Both [the]Transmission Provider and [the]Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If [the]Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, [the]Transmission Provider must provide [the]Interconnection Customer a written technical explanation outlining why [the]Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

Substation Network Upgrades *shall mean Network Upgrades that are required at the substation located at the Point of Interconnection.*

Surplus Interconnection Service shall mean any unneeded portion of Interconnection Service established in a Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Network Upgrades *shall mean Network Upgrades that are required beyond the substation located at the Point of Interconnection.*

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transitional Cluster Study *shall mean an Interconnection Study evaluating a Cluster of Interconnection Requests during the transition to the Cluster Study Process, as set forth in Section 5.1.1.2 of this LGIP.*

Transitional Cluster Study Report *shall mean the report issued following completion of a Transitional Cluster Study pursuant to Section 5.1.1.2 of this LGIP.*

Transitional Serial Interconnection Facilities Study *shall mean an Interconnection Facilities Study evaluating an Interconnection Request on a serial basis during the transition to the Cluster Study Process, as set forth in Section 5.1.1.1 of this LGIP.*

Transitional Serial Interconnection Facilities Study Report *shall mean the report issued following completion of a Transitional Interconnection Facilities Study pursuant to Section 5.1.1.1 of this LGIP.*

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by [the]Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Withdrawal Penalty *shall mean the penalty assessed by Transmission Provider to an Interconnection Customer that chooses to withdraw or is deemed withdrawn from Transmission Provider's interconnection queue or whose Generating Facility does not otherwise reach Commercial Operation. The calculation of the Withdrawal Penalty is set forth in Section 3.7.1 of this LGIP.*

Section 2. Scope and Application

2.1 Application of Standard Large Generator Interconnection Procedures.

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability.

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider [will use the same Reasonable Efforts]*shall* process[ing] and analyze[ing] Interconnection Requests from all Interconnection Customers comparably, *regardless of* whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data.

Transmission Provider shall maintain base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list on either its OASIS site or a password-protected website, subject to confidentiality provisions in LGIP Section 13.1. In addition, Transmission Provider shall maintain network models and underlying assumptions on either its OASIS site or a password-protected website. Such network models and underlying assumptions should reasonably represent those used during the most recent interconnection study and be representative of current system conditions. If Transmission Provider posts this information on a password-protected website, a link to the information must be provided on Transmission Provider's OASIS site. Transmission Provider is permitted to require that Interconnection Customers, OASIS site users and password-protected website users sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (2) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Interconnection Requests

3.1 [General.] ***Interconnection Requests.***

3.1.1 Study Deposits.

3.1.1.1 Study Deposit.

[An]Interconnection Customer shall submit to Transmission Provider*, during a Cluster Request Window*, an Interconnection Request in the form of Appendix 1 to this LGIP*, an application fee of $5,000,* and a refundable *study* deposit of[$10,000]:

a. *$35,000 plus $1,000 per MW for Interconnection Requests ≥ 20 MW < 80 MW, or*;
b. $150,000 for Interconnection Requests ≥ 80 MW < 200 MW; or
c. $250,000 for Interconnection Requests ≥ 200 MW.

Transmission Provider shall apply the *study* deposit toward the cost of *the Cluster* [an Interconnection Feasibility]Study Process.

3.1.2 Submission.

Interconnection Customer shall submit a separate Interconnection Request for each site [and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site]. *Where multiple Generating Facilities share a site, Interconnection Customer(s) may submit separate Interconnection Requests or a single Interconnection Request*. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at [the]*a* Scoping Meeting *within the Customer Engagement Window* to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point[(s)] of Interconnection to be studied no later than the execution of the [Interconnection Feasibility Study Agreement.]*Cluster Study Agreement. For purposes of clustering Interconnection Requests, Transmission Provider may propose changes to the requested Point of Interconnection to facilitate efficient interconnection of Interconnection Customers at common Point(s) of Interconnection. Transmission Provider shall notify Interconnection Customers in writing of any intended changes to the requested Point of Interconnection within the Customer Engagement Window, and the Point of Interconnection shall only change upon mutual agreement.*

Transmission Provider shall have a process in place to consider requests for Interconnection Service below the Generating Facility Capacity. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of Interconnection Facilities, Network Upgrades, and associated costs, but may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the system, with the study costs borne by [the]Interconnection Customer. If after the additional studies are complete, Transmission Provider determines

that additional Network Upgrades are necessary, then Transmission Provider must: (1) specify which additional Network Upgrade costs are based on which studies; and (2) provide a detailed explanation of why the additional Network Upgrades are necessary. Any Interconnection Facility and/or Network Upgrade costs required for safety and reliability also would be borne by [the]Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems shall be established in Appendix C of that executed, or requested to be filed unexecuted, LGIA.

Transmission Provider shall have a process in place to study Generating Facilities that include at least one electric storage resource using operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) that reflect the proposed charging behavior of the Generating Facility as requested by Interconnection Customer, unless Transmission Provider determines that Good Utility Practice, including Applicable Reliability Standards, otherwise requires the use of different operating assumptions. If Transmission Provider finds Interconnection Customer's requested operating assumptions conflict with Good Utility Practice, Transmission Provider must provide Interconnection Customer an explanation in writing of why the submitted operating assumptions are insufficient or inappropriate by no later than thirty (30) Calendar Days before the end of the Customer Engagement Window and allow Interconnection Customer to revise and resubmit requested operating assumptions one time at least ten (10) Calendar Days prior to the end of the Customer Engagement Window. Transmission Provider shall study these requests for Interconnection Service, with the study costs borne by Interconnection Customer, using the submitted operating assumptions for purposes of Interconnection Facilities, Network Upgrades, and associated costs. These requests for Interconnection Service also may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the system, with the study costs borne by Interconnection Customer. Interconnection Customer's Generating Facility may be subject to additional control technologies as well as testing and validation of such additional control technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems shall be set forth in Appendix C of the Interconnection Customer's LGIA.

3.2 Identification of Types of Interconnection Services.

At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facilit[y]*ies* Study Agreement is executed. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed

under a lower level of interconnection service to the extent that only certain upgrades will be completed.

3.2.1 Energy Resource Interconnection Service.

3.2.1.1 The Product.

Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

3.2.1.2 The Study.

The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Large Generating Facility*, except for Generating Facilities that include at least one electric storage resource that request to use operating assumptions pursuant to Section 3.1.2, unless the Transmission Provider determines that Good Utility Practice, including Applicable Reliability Standards, otherwise requires the use of different operating assumptions,* and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Large Generating Facility without requiring additional Network Upgrades.

3.2.2 Network Resource Interconnection Service.

3.2.2.1 The Product.

Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service Allows Interconnection Customer's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

3.2.2.2 The Study.

The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, *except for Generating Facilities that include at least one electric storage resource that request to use, and for which Transmission Provider approves, operating assumptions pursuant to Section 3.1.2,* the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Large Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.3 Utilization of Surplus Interconnection Service.

Transmission Provider must provide a process that allows an Interconnection Customer to utilize or transfer Surplus Interconnection Service at an existing Point of Interconnection. The original Interconnection Customer or one of its affiliates shall have priority to utilize Surplus Interconnection Service. If the existing Interconnection Customer or one of its affiliates does not exercise its priority, then that service may be made available to other potential Interconnection Customers.

3.3.1 Surplus Interconnection Service Request.

Surplus Interconnection Service requests may be made by the existing Interconnection Customer [whose Generating Facility is already interconnected]or one of its affiliates or may *be submitted once Interconnection Customer has executed the LGIA or requested that the LGIA be filed unexecuted*. Surplus Interconnection Service requests also may be made by another Interconnection Customer. Transmission Provider shall provide a process for evaluating Interconnection Requests for Surplus Interconnection Service. Studies for Surplus Interconnection Service shall consist of reactive power, short circuit/fault duty, stability analyses, and any other appropriate studies. Steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required

reliability conditions are studied. If the Surplus Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original system impact study *report or Cluster Study Report* is not available for the Surplus Interconnection Service, both off-peak and peak analysis may need to be performed for the existing Generating Facility associated with the request for Surplus Interconnection Service. The reactive power, short circuit/fault duty, stability, and steady-state analyses for Surplus Interconnection Service will identify any additional Interconnection Facilities and/or Network Upgrades necessary.

Transmission Provider shall study Surplus Interconnection Service requests for a Generating Facility that includes at least one electric storage resource using operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) that reflect the proposed charging behavior of the Generating Facility as requested by Interconnection Customer, unless Transmission Provider determines that Good Utility Practice, including Applicable Reliability Standards, otherwise requires the use of different operating assumptions.

3.4 Valid Interconnection Request.

3.4.1 Cluster Request Window.

Transmission Provider shall accept Interconnection Requests during a forty-five (45) Calendar Day period (the Cluster Request Window). The initial Cluster Request Window shall open for Interconnection Requests beginning {Transmission Provider to provide number of Calendar Days} after the conclusion of the transition process set out in Section 5.1 of this LGIP and successive Cluster Request Windows shall open annually every {Transmission Provider to provide Month and Day (e.g., January 1)} thereafter.

3.4.[1]*2* Initiating an Interconnection Request.

An Interconnection Customer seeking to join a Cluster shall submit its Interconnection Request to Transmission Provider within, and no later than the close of, the Cluster Request Window. Interconnection Requests submitted outside of the Cluster Request Window will not be considered. To initiate an Interconnection Request, Interconnection Customer must submit all of the following:

(i) [a $10,000 deposit,]*applicable study deposit amount, pursuant to Section 3.1.1.1 of this LGIP,*

(ii) a completed application in the form of Appendix 1, [and]

(iii) demonstration of *no less than ninety percent* (*90%)* Site Control or [a posting of an additional deposit of $10,000. Such deposits shall be applied toward any Interconnection Studies, pursuant to the Interconnection Request. If Interconnection Customer demonstrates Site Control within the cure period specified in Section 3.4.3 after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.] *(1) a signed affidavit from an officer of the company indicating that Site Control is unobtainable due to regulatory limitations as such term is defined by the Transmission Provider; and (2) documentation sufficiently describing and explaining the source and effects of such regulatory limitations, including a description of any conditions that must be met to satisfy the regulatory limitations and the anticipated time by which Interconnection Customer expects to satisfy the regulatory requirements and (3) a deposit in lieu of Site Control of $10,000 per MW, subject to a minimum of $500,000 and a maximum of $2,000,000. Interconnection Requests from multiple Interconnection Customers for multiple Generating Facilities that share a site must include a contract or other agreement that allows for shared land use.*

(iv) Generating Facility Capacity (MW) (and requested Interconnection Service level if the requested Interconnection Service is less than the Generating Facility Capacity),

(v) If applicable, (1) the requested operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) to be used by Transmission Provider that reflect the proposed charging behavior of the Generating Facility that includes at least one electric storage resource, and (2) a description of any control technologies (software and/or hardware) that will limit the operation of the Generating Facility to the operating assumptions submitted by Interconnection Customer.

(vi) A Commercial Readiness Deposit equal to two times the study deposit described in Section 3.1.1.1 of this LGIP in the form of an irrevocable letter of credit or cash. This Commercial Readiness Deposit is refunded to Interconnection Customer according to Section 3.7 of this LGIP,

(vii) A Point of Interconnection, and

(viii) Whether the Interconnection Request shall be studied for Network Resource Interconnection Service or for Energy Resource Interconnection Service, consistent with Section 3.2 of this LGIP.

An Interconnection Customer that submits a deposit in lieu of Site Control due to demonstrated regulatory limitations must demonstrate that it is taking identifiable steps

to secure the necessary regulatory approvals from the applicable federal, state, and/or tribal entities before execution of the Cluster Study Agreement. Such deposit will be held by Transmission Provider until Interconnection Customer provides the required Site Control demonstration for its point in the Cluster Study Process. Interconnection Customers facing qualifying regulatory limitations must demonstrate one-hundred percent (100%) Site Control within one-hundred eighty (180) Calendar Days of the effective date of the LGIA.

Interconnection Customer shall promptly inform Transmission Provider of any material change to Interconnection Customer's demonstration of Site Control under Section 3.4.2(iii) of this LGIP. If Transmission Provider determines, based on Interconnection Customer's information, that Interconnection Customer no longer satisfies the Site Control requirement, Transmission Provider shall give Interconnection Customer ten (10) Business Days to demonstrate satisfaction with the applicable requirement subject to Transmission Provider's approval. Absent such, Transmission Provider shall deem the Interconnection Request withdrawn pursuant to Section 3.7 of this LGIP.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for Transmission Provider's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

3.4.[2]*3* Acknowledgment of Interconnection Request.

Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.4.[3]*4* Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in Section [3.4.1]*3.4.2 of this LGIP* have been received by Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section [3.4.1]*3.4.2 of this LGIP*, Transmission Provider shall notify Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such

failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice *but no later than the close of the Cluster Request Window. At any time, if Transmission Provider finds that the technical data provided by Interconnection Customer is incomplete or contains errors, Interconnection Customer and Transmission Provider shall work expeditiously and in good faith to remedy such issues. In the event that* [Failure by] Interconnection Customer *fails* to comply with this Section 3.4.[3]*4 of this LGIP, Transmission Providers shall deem the Interconnection Request withdrawn (without the cure period provided under Section 3.7 of this LGIP), the application fee is forfeited to the Transmission Provider, and the study deposit and Commercial Readiness Deposit shall be returned to Interconnection Customer* [shall be treated in accordance with Section 3.7].

3.4.5 Customer Engagement Window.

Upon the close of each Cluster Request Window, Transmission Provider shall open a sixty (60) Calendar Day period (Customer Engagement Window). During the Customer Engagement Window, Transmission Provider shall hold a Scoping Meeting with all interested Interconnection Customers. Notwithstanding the preceding requirements and upon written consent of all Interconnection Customers within the Cluster, Transmission Provider may shorten the Customer Engagement Window and begin the Cluster Study. Within ten (10) Business Days of the opening of the Customer Engagement Window, Transmission Provider shall post on its OASIS a list of Interconnection Requests for that Cluster. The list shall identify, for each anonymized Interconnection Request: (1) the requested amount of Interconnection Service; (2) the location by county and state; (3) the station or transmission line or lines where the interconnection will be made; (4) the projected In-Service Date; (5) the type of Interconnection Service requested; and (6) the type of Generating Facility or Facilities to be constructed, including fuel types, such as coal, natural gas, solar, or wind. The Transmission Provider must ensure that project information is anonymized and does not reveal the identity or commercial information of interconnection customers with submitted requests. During the Customer Engagement Window, Transmission Provider shall provide to Interconnection Customer a non-binding updated good faith estimate of the cost and timeframe for completing the Cluster Study and a Cluster Study Agreement to be executed prior to the close of the Customer Engagement Window.

At the end of the Customer Engagement Window, all Interconnection Requests deemed valid that have executed a Cluster Study Agreement in the form of Appendix 2 to this LGIP shall be included in the Cluster Study. Any Interconnection Requests not deemed valid at the close of the Customer Engagement Window shall be deemed withdrawn (without the cure period provided under Section 3.7 of this LGIP) by Transmission Provider, the application fee shall be forfeited to the Transmission Provider, and the

Transmission Provider shall return the study deposit and Commercial Readiness Deposit to Interconnection Customer. Immediately following the Customer Engagement Window, Transmission Provider shall initiate the Cluster Study described in Section 7 of this LGIP.

3.4.[4]*6 Cluster Study* Scoping Meeting*s*.

[Within ten (10) Business Days after receipt of a valid Interconnection Request]*During the Customer Engagement Window*, Transmission Provider shall [establish a date agreeable to]*hold a Scoping Meeting with all Interconnection Customers whose valid Interconnection Requests were received in that Cluster Request Window.*

The purpose of the *Cluster Study* Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data *and earlier study evaluations* that would reasonably be expected to impact such interconnection options, *to discuss the Cluster Study materials posted to OASIS pursuant to Section 3.5 of this LGIP, if applicable, and* to analyze such information [and to determine the potential feasible Points of Interconnection]. Transmission Provider and Interconnection Customer*(s)* will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider and Interconnection Customer*(s)* will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer*(s)* shall designate its Point of Interconnection*.*[, pursuant to Section 6.1,] and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose. *If the Cluster Study Scoping Meeting consists of more than one Interconnection Customer, Transmission Provider shall issue, no later than fifteen (15) Business Days after the commencement of the Customer Engagement Window, and Interconnection Customer shall execute a non-disclosure agreement prior to a group Cluster Study Scoping Meeting, which will provide for confidentiality of identifying commercially sensitive information pertaining to any other Interconnection Customers.*

3.5 OASIS Posting.

3.5.1 *OASIS Posting.*

Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position;

(vi) the type of Interconnection Service being requested; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed[(combined cycle, base load or combustion turbine and fuel type)]; and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of Interconnection Customer until Interconnection Customer executes an LGIA or requests that Transmission Provider file an unexecuted LGIA with FERC. Before holding a Scoping Meeting with its Affiliate, Transmission Provider shall post on OASIS an advance notice of its intent to do so. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Large Generating Facility's In-Service Date.

3.5.2 Requirement to Post Interconnection Study Metrics.

Transmission Provider will maintain on its OASIS or its website summary statistics related to processing Interconnection Studies pursuant to Interconnection Requests, updated quarterly. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider's OASIS site. For each calendar quarter, Transmission Providers must calculate and post the information detailed in [sections]*Sections* 3.5.2.1 through 3.5.2.4 *of this LGIP*.

3.5.2.1 Interconnection [Feasibility Studies]*Cluster Study* Processing Time.

(A) Number of Interconnection Requests that had [Interconnection Feasibility]*Cluster* Studies completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Requests that had [Interconnection Feasibility]*Cluster* Studies completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than [[timeline as listed in Transmission Provider's LGIP]]*one hundred fifty (150) Calendar Days* after [receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Feasibility Study Agreement]*the close of the Customer Engagement Window*,

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete [Interconnection Feasibility] *Cluster* Studies where such Interconnection Requests had executed [Interconnection Feasibility]*a Cluster* Study Agreement[s] received by Transmission Provider more than [[timeline as listed in

Transmission Provider's LGIP]]*one hundred fifty (150) Calendar Days* before the reporting quarter end,

(D) Mean time (in days), [Interconnection Feasibility]*Cluster* Studies completed within Transmission Provider's coordinated region during the reporting quarter, from the [date when Transmission Provider received the executed Interconnection Feasibility Study Agreement]*commencement of the Cluster Study* to the date when Transmission Provider provided the completed [Interconnection Feasibility]*Cluster* Study *Report* to [the] Interconnection Customer,

(E) Mean time (in days), Cluster Studies were completed within Transmission Provider's coordinated region during the reporting quarter, from the close of the Cluster Request Window to the date when Transmission Provider provided the completed Cluster Study Report to Interconnection Customer.

[(E)]*(F)* Percentage of [Interconnection Feasibility]*Cluster* Studies exceeding [[timeline as listed in Transmission Provider's LGIP]]*one hundred fifty (150) Calendar Days* to complete this reporting quarter, calculated as the sum of 3.5.2.1(B) plus 3.5.2.1(C) divided by the sum of 3.5.2.1(A) plus 3.5.2.1(C)[)].

3.5.2.2 [Interconnection System Impact Studies]*Cluster Restudies* Processing Time.

(A) Number of Interconnection Requests that had [Interconnection System Impact Studies]*Cluster Restudies* completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Requests that had [Interconnection System Impact Studies]*Cluster Restudies* completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than [[timeline as listed in Transmission Provider's LGIP]]*one hundred fifty (150) Calendar Days* after [receipt by] Transmission Provider *notifies Interconnection Customers in the Cluster that a Cluster Restudy is required pursuant to Section 7.5(4) of this LGIP* [of the Interconnection Customer's executed Interconnection System Impact Study Agreement],

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete [System Impact Studies]*Cluster Restudies* where *Transmission Provider notified Interconnection Customers in the Cluster that a Cluster Restudy is required pursuant to Section 7.5(4) of this LGIP* [such Interconnection Requests had executed Interconnection System Impact Study Agreements received by Transmission Provider] more than [[timeline as listed in Transmission Provider's LGIP]]*one hundred fifty (150) Calendar Days* before the reporting quarter end,

(D) Mean time (in days), [Interconnection System Impact Studies]*Cluster Restudies* completed within Transmission Provider's coordinated region during the reporting quarter, from the date when Transmission Provider *notifies Interconnection Customers in the Cluster that a Cluster Restudy is required pursuant to Section 7.5(4) of this LGIP* [received the executed Interconnection System Impact Study Agreement] to the date when Transmission Provider provided the completed [Interconnection System Impact Study]*Cluster Restudy Report* to [the]Interconnection Customer,

(E) Mean time (in days), Cluster Restudies completed within Transmission Provider's coordinated region during the reporting quarter, from the close of the Cluster Request Window to the date when Transmission Provider provided the completed Cluster Restudy Report to Interconnection Customer.

[(E)]*(F)* Percentage of [Interconnection System Impact Studies]*Cluster Restudies* exceeding [[timeline as listed in Transmission Provider's LGIP]]*one hundred fifty (150) Calendar Days* to complete this reporting quarter, calculated as the sum of 3.5.2.2(B) plus 3.5.2.2(C) divided by the sum of 3.5.2.2(A) plus 3.5.2.2(C)).

3.5.2.3 Interconnection Facilities Studies Processing Time.

(A) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than {timeline as listed in Transmission Provider's LGIP} after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Service requests with ongoing incomplete Interconnection Facilities Studies where such Interconnection Requests had executed Interconnection Facilities Studies Agreement received by Transmission Provider more than {timeline as listed in Transmission Provider's LGIP} before the reporting quarter end,

(D) Mean time (in days), for Interconnection Facilities Studies completed within Transmission Provider's coordinated region during the reporting quarter, calculated from the date when Transmission Provider received the executed Interconnection Facilities Study Agreement to the date when Transmission Provider provided the completed Interconnection Facilities Study to the Interconnection Customer,

(E) Mean time (in days), Interconnection Facilities Studies completed within Transmission Provider's coordinated region during the reporting quarter, from the close of the Cluster Request Window to the date when Transmission Provider provided the completed Interconnection Facilities Study to Interconnection Customer.

[(E)]*(F)* Percentage of delayed Interconnection Facilities Studies this reporting quarter, calculated as the sum of 3.5.2.3(B) plus 3.5.2.3(C) divided by the sum of 3.5.2.3(A) plus 3.5.2.3(C)).

3.5.2.4 Interconnection Service Requests Withdrawn from Interconnection Queue.

(A) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter,

(B) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of any interconnection studies or execution of any interconnection study agreements,

(C) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of [an Interconnection System Impact]*a Cluster* Study,

(D) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of an Interconnection Facilities Study,

(E) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue after execution of a generator interconnection agreement or Interconnection Customer requests the filing of an unexecuted, new interconnection agreement,

(F) Mean time (in days), for all withdrawn Interconnection Requests, from the date when the request was determined to be valid to when Transmission Provider received the request to withdraw from the queue.

3.5.3

Transmission Provider is required to post on OASIS or its website the measures in paragraph 3.5.2.1(A) through paragraph 3.5.2.4(F) for each calendar quarter within 30 days of the end of the calendar quarter. Transmission Provider will keep the quarterly measures posted on OASIS or its website for three calendar years with the first required report to be in the first quarter of 2020. If Transmission Provider retains this information

on its website, a link to the information must be provided on Transmission Provider's OASIS site.

3.5.4

In the event that any of the values calculated in paragraphs 3.5.2.1(E), 3.5.2.2(E) or 3.5.2.3(E) exceeds 25 percent for two consecutive calendar quarters, Transmission Provider will have to comply with the measures below for the next four consecutive calendar quarters and must continue reporting this information until Transmission Provider reports four consecutive calendar quarters without the values calculated in 3.5.2.1(E), 3.5.2.2(E) or 3.5.2.3(E) exceeding 25 percent for two consecutive calendar quarters:

(i) Transmission Provider must submit a report to the Commission describing the reason for each *Cluster Study, Cluster Restudy, or individual Interconnection Facilities S*[s]tudy [or group of clustered studies]pursuant to[an] *one or more* Interconnection Request*(s)* that exceeded its deadline (i.e., [45,]*150*, 90 or 180 days) for completion [(excluding any allowance for Reasonable Efforts)]. Transmission Provider must describe the reasons for each study delay and any steps taken to remedy these specific issues and, if applicable, prevent such delays in the future. The report must be filed at the Commission within 45 days of the end of the calendar quarter.

(ii) Transmission Provider shall aggregate the total number of employee-hours and third party consultant hours expended towards interconnection studies within its coordinated region that quarter and post on OASIS or its website. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider's OASIS site. This information is to be posted within 30 days of the end of the calendar quarter.

3.6 Coordination with Affected Systems.

Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators[and, if possible, include those results in its applicable Interconnection Study within the time frame specified in this LGIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this LGIP]. Interconnection Customer will cooperate with Transmission Provider *and Affected System Operator* in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

A Transmission Provider *whose system may be impacted by a proposed interconnection on another transmission provider's transmission system* [which may be an Affected System] shall cooperate with the [T]*t*ransmission [P]*p*rovider with whom interconnection

has been requested in all matters related to the conduct of studies and the determination of modifications to *Transmission Provider's Transmission System*[Affected Systems].

3.6.1 Initial Notification.

Transmission Provider must notify Affected System Operator of a potential Affected System impact caused by an Interconnection Request within ten (10) Business Days of the completion of the Cluster Study or, if the potential Affected System impact is only determined in the Cluster Restudy, the completion of the Cluster Restudy.

At the time of initial notification, Transmission Provider must provide Interconnection Customer with a list of potential Affected Systems, along with relevant contact information.

3.7 Withdrawal.

Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in Section 13.5 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider's receipt of notice described above. Interconnection Customer must pay all monies due to Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

If Interconnection Customer withdraws its Interconnection Request or is deemed withdrawn by Transmission Provider under Section 3.7 of this LGIP, Transmission Provider shall (i) update the OASIS Queue Position posting; (ii) *impose the Withdrawal Penalty described in Section 3.7.1 of this LGIP*; and *(iii)* refund to Interconnection Customer any portion *of the refundable portion of* Interconnection Customer's *study*

deposit [or study payments] that exceeds the costs that Transmission Provider has incurred, including interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. *Transmission Provider shall also refund any portion of the Commercial Readiness Deposit not applied to the Withdrawal Penalty and, if applicable, the deposit in lieu of site control.* In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 13.1 *of this LGIP*, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

3.7.1 Withdrawal Penalty.

Interconnection Customer shall be subject to a Withdrawal Penalty if it withdraws its Interconnection Request or is deemed withdrawn, or the Generating Facility does not otherwise reach Commercial Operation unless: (1) the withdrawal does not have a material impact on the cost or timing of any Interconnection Request with an equal or lower Queue Position; (2) Interconnection Customer withdraws after receiving Interconnection Customer's most recent Cluster Restudy Report and the Network Upgrade costs assigned to the Interconnection Request identified in that report have increased by more than twenty-five percent (25%) compared to costs identified in Interconnection Customer's preceding Cluster Study Report or Cluster Restudy Report; or (3) Interconnection Customer withdraws after receiving Interconnection Customer's Interconnection Facilities Study Report and the Network Upgrade costs assigned to the Interconnection Request identified in that report have increased by more than one hundred percent (100%) compared to costs identified in the Cluster Study Report.

3.7.1.1 Calculation of the Withdrawal Penalty.

If Interconnection Customer withdraws its Interconnection Request or is deemed withdrawn prior to the commencement of the initial Cluster Study, Interconnection Customer shall not be subject to a Withdrawal Penalty. If Interconnection Customer withdraws, is deemed withdrawn, or otherwise does not reach Commercial Operation at any point after the commencement of the initial Cluster Study, that Interconnection Customer's Withdrawal Penalty will be the greater of: (1) the Interconnection Customer's study deposit required under Section 3.1.1.1 of this LGIP; or (2) as follows in (a) –(d):

> *(a) If Interconnection Customer withdraws or is deemed withdrawn during the Cluster Study or after receipt of a Cluster Study Report, but prior to commencement of the Cluster Restudy or Interconnection Facilities Study, Interconnection Customer shall be charged two (2) times its actual allocated cost of all studies performed for Interconnection Customers in the Cluster up until that point in the interconnection study process.*

(b) If Interconnection Customer withdraws or is deemed withdrawn during the Cluster Restudy or after receipt of any applicable restudy reports issued pursuant to Section 7.5 of this LGIP, but prior to commencement of the Interconnection Facilities Study, Interconnection Customer shall be charged five percent (5%) its estimated Network Upgrade costs.

(c) If Interconnection Customer withdraws or is deemed withdrawn during the Interconnection Facilities Study, after receipt of the Interconnection Facilities Study Report issued pursuant to Section 8.3 of this LGIP, or after receipt of the draft LGIA but before Interconnection Customer has executed an LGIA or has requested that its LGIA be filed unexecuted, and has satisfied the other requirements described in Section 11.3 of this LGIP (i.e., Site Control demonstration, LGIA Deposit, reasonable evidence of one or more milestones in the development of the Generating Facility), Interconnection Customer shall be charged ten percent (10%) its estimated Network Upgrade costs.

(d) If Interconnection Customer has executed an LGIA or has requested that its LGIA be filed unexecuted and has satisfied the other requirements described in Section 11.3 of this LGIP (i.e., Site Control demonstration, LGIA Deposit, reasonable evidence of one or more milestones in the development of the Generating Facility) and subsequently withdraws its Interconnection Request or if Interconnection Customer's Generating Facility otherwise does not reach Commercial Operation, that Interconnection Customer's Withdrawal Penalty shall be twenty percent (20%) its estimated Network Upgrade costs.

3.7.1.2 Distribution of the Withdrawal Penalty.

3.7.1.2.1 Initial Distribution of Withdrawal Penalties Prior to Assessment of Network Upgrade Costs Previously Shared with Withdrawn Interconnection Customers in the Same Cluster

For a single cluster, Transmission Provider shall hold all Withdrawal Penalty funds until all Interconnection Customers in that Cluster have either: (1) withdrawn or been deemed withdrawn; (2) executed an LGIA; or (3) requested an LGIA to be filed unexecuted. Any Withdrawal Penalty funds collected from the Cluster shall first be used to fund studies conducted under the Cluster Study Process for Interconnection Customers in the same Cluster that have executed the LGIA or requested the LGIA to be filed unexecuted. Next, after the Withdrawal Penalty funds are applied to relevant study costs in the same Cluster, Transmission Provider will apply the remaining Withdrawal Penalty funds to reduce net increases, for Interconnection Customers in the same Cluster, in Interconnection Customers' Network Upgrade cost assignment and associated financial security requirements under Article 11.5 of the pro forma LGIA attributable to the

impacts of withdrawn Interconnection Customers that shared an obligation with the remaining Interconnection Customers to fund a Network Upgrade, as described in more detail in Sections 3.7.1.2.3 and 3.7.1.2.4.

Withdrawal Penalty funds shall first be applied as a refund to invoiced study costs for Interconnection Customers in the same Cluster that did not withdraw within 30 Calendar Days of such Interconnection Customers executing their LGIA or requesting to have their LGIA filed unexecuted. Distribution of Withdrawal Penalty funds within one specific Cluster Study for study costs shall not exceed the total actual Cluster Study costs. Withdrawal Penalty funds applied to study costs shall be allocated within the same Cluster to Interconnection Customers in a manner consistent with the Transmission Provider's method in Section 13.3 of this LGIP for allocating the costs of interconnection studies conducted on a clustered basis. Transmission Provider shall post the balance of Withdrawal Penalty funds held by Transmission Provider but not yet dispersed on its OASIS site and update this posting on a quarterly basis.

If an Interconnection Customer withdraws after it executes, or requests the unexecuted filing of, its LGIA, Transmission Provider shall first apply such Interconnection Customer's Withdrawal Penalty funds to any restudy costs required due to the Interconnection Customer's withdrawal as a credit to as-yet-to be invoiced study costs to be charged to the remaining Interconnection Customers in the same Cluster in a manner consistent with the Transmission Provider's method in Section 13.3 of this LGIP for allocating the costs of interconnection studies conducted on a clustered basis. Distribution of the Withdrawal Penalty funds for such restudy costs shall not exceed the total actual restudy costs.

3.7.1.2.2 Assessment of Network Upgrade Costs Previously Shared with Withdrawn Interconnection Customers in the Same Cluster

If Withdrawal Penalty funds remain for the same Cluster after the Withdrawal Penalty funds are applied to relevant study costs, Transmission Provider will determine if the withdrawn Interconnection Customers, at any point in the Cluster Study Process, shared cost assignment for one or more Network Upgrades with any remaining Interconnection Customers in the same Cluster based on the Cluster Study Report, Cluster Restudy Report(s), Interconnection Facilities Study Report, and any subsequent issued restudy report issued for the Cluster.

In section 3.7.1.2 of this LGIP, shared cost assignments for Network Upgrades refers to the cost of Network Upgrades still needed for the same Cluster for which an Interconnection Customer, prior to withdrawing its Interconnection Request, shared the obligation to fund along with Interconnection Customers that have executed an LGIA, or requested the LGIA to filed unexecuted.

If Transmission Provider's assessment determines that there are no shared cost assignments for any Network Upgrades in the same Cluster for the withdrawn Interconnection Customer, or determines that the withdrawn Interconnection Customer's withdrawal did not cause a net increase in the shared cost assignment for any remaining Interconnection Customers' Network Upgrade(s) in the same Cluster, Transmission Provider will return any remaining Withdrawal Penalty funds to the withdrawn Interconnection Customer(s). Such remaining Withdrawal Penalty funds will be returned to withdrawn Interconnection Customers based on the proportion of each withdrawn Interconnection Customer's contribution to the total amount of Withdrawal Penalty funds collected for the Cluster (i.e., the total amount before the initial disbursement required under Section 3.7.1.2.1 of this LGIP). Transmission Provider must make such disbursement within sixty (60) Calendar Days of the date on which all Interconnection Customers in the same Cluster have either: (1) withdrawn or been deemed withdrawn; (2) executed an LGIA; or (3) requested an LGIA to be filed unexecuted. For the withdrawn Interconnection Customers that Transmission Provider determines have caused a net increase in the shared cost assignment for one or more Network Upgrade(s) in the same Cluster under subsection 3.7.1.2.3(a), Transmission Provider will determine each such withdrawn Interconnection Customers' Withdrawal Penalty funds remaining balance that will be applied toward net increases in Network Upgrade shared costs calculated under subsections 3.7.1.2.3(a) and 3.7.1.2.3(b) based on each such withdrawn Interconnection Customer's proportional contribution to the total amount of Withdrawal Penalty funds collected for the same Cluster (i.e., the total amount before the initial disbursement requirement under Section 3.7.1.2.1 of this LGIP).

If the Transmission Provider's assessment determines that there are shared cost assignments for Network Upgrades in the same Cluster, Transmission Provider will calculate the remaining Interconnection Customers' net increase in cost assignment for Network Upgrades due to a shared cost assignment for Network Upgrades with the withdrawn Interconnection Customer and distribute Withdrawal Penalty funds as described in Section 3.7.1.2.3, depending on whether the withdrawal occurred before the withdrawing Interconnection Customer executed the LGIA (or filed unexecuted), as described in subsection 3.7.1.2.3(a), or after such execution (or filing unexecuted) of an LGIA, as described in subsection 3.7.1.2.3(b).

As discussed in subsection 3.7.1.2.4, Transmission Provider will amend executed (or filed unexecuted) LGIAs of the remaining Interconnection Customers in the same Cluster to apply the remaining Withdrawal Penalty funds to reduce net increases in Interconnection Customers' Network Upgrade cost assignment and associated financial security requirements under Article 11.5 of the pro forma LGIA attributable to the impacts of withdrawn Interconnection Customers on Interconnection Customers remaining in the same Cluster that had a shared cost assignment for Network Upgrades with the withdrawn Interconnection Customers.

3.7.1.2.3 Impact Calculations

3.7.1.2.3(a) Impact Calculation for Withdrawals During the Cluster Study Process

If an Interconnection Customer withdraws before it executes, or requests the unexecuted filing of, its LGIA, the Transmission Provider will distribute in the following manner the Withdrawal Penalty funds to reduce the Network Upgrade cost impact on the remaining Interconnection Customers in the same Cluster who had a shared cost assignment for a Network Upgrade with the withdrawn Interconnection Customer.

To calculate the reduction in the remaining Interconnection Customers' net increase in Network Upgrade costs and associated financial security requirements under Article 11.5 of the pro forma LGIA, the Transmission Provider will determine the financial impact of a withdrawing Interconnection Customer on other Interconnection Customers in the same Cluster that shared an obligation to fund the same Network Upgrade(s). Transmission Provider shall calculate this financial impact once all the Interconnection Customers in the same Cluster either: (1) have withdrawn or have been deemed withdrawn; (2) executed an LGIA; or (3) request an LGIA to be filed unexecuted. Transmission Provider will perform the financial impact calculation using the following steps.

First, Transmission Provider must determine which withdrawn Interconnection Customers shared an obligation to fund Network Upgrades with Interconnection Customers from the same Cluster that have LGIAs that are executed or have been requested to be filed unexecuted. Next, Transmission Provider shall perform the calculation of the financial impact of a withdrawal on another Interconnection Request in the same Cluster by performing a comparison of the Network Upgrade cost estimates between each of the following:

(1) Cluster Study phase to Cluster Restudy phase (if Cluster Restudy was necessary);

(2) Cluster Restudy phase to Facilities Study phase (if a Cluster Restudy was necessary);

(3) Cluster Study phase to Facilities Study phase (if no Cluster Restudy was performed);

(4) Facilities Study phase to any subsequent restudy that was performed before the execution or filing of an unexecuted LGIA;

(5) the restudy to the executed, or filed unexecuted, LGIA (if a restudy was performed after the Facilities Study phase and before the execution or filing of an unexecuted LGIA).

If, based on the above calculations, Transmission Provider determines:

(i) that the costs assigned to an Interconnection Customer in the same Cluster for Network Upgrades that a withdrawn Interconnection Customer shared cost assignment for increased between any two studies, and

(ii) after the impacted Interconnection Customer's LGIA was executed or filed unexecuted, the Interconnection Customer's cost assignment for the relevant Network Upgrade is greater than it was prior to the withdrawal of the Interconnection Customer in the same Cluster that shared cost assignment for the Network Upgrade,

then Transmission Provider shall apply the withdrawn Interconnection Customer's Withdrawal Penalty funds that has not already been applied to study costs in the amount of the financial impact by reducing, in the same Cluster, the remaining Interconnection Customer's Network Upgrade costs and associated financial security requirements under Article 11.5 of the pro forma LGIA.

If Transmission Provider determines that more than one Interconnection Customer in the same Cluster was financially impacted by the same withdrawn Interconnection Customer, Transmission Provider will apply the relevant withdrawn Interconnection Customer's Withdrawal Penalty funds that has not already been applied to study costs to reduce the financial impact to each Interconnection Customer based on each Interconnection Customer's proportional share of the financial impact, as determined by either the proportional impact method if it is a System Network Upgrade or on a per capita basis if it is a Substation Network Upgrade, as described under Section 4.2.1 of this LGIP.

3.7.1.2.3(b) Impact Calculation for Withdrawals in the Same Cluster After the Cluster Study Process

If an Interconnection Customer withdraws after it executes, or requests the unexecuted filing of, its LGIA, Transmission Provider will distribute in the following manner the remaining Withdrawal Penalty funds to reduce the Network Upgrade cost impact on the remaining Interconnection Customers in the same Cluster who had a shared cost assignment with the withdrawn Interconnection Customer for one or more Network Upgrades.

Transmission Provider will determine the financial impact on the remaining Interconnection Customers in the same Cluster within 30 calendar days after the

withdrawal occurs. The Transmission Provider will determine that financial impact by comparing the Network Upgrade cost funding obligations the Interconnection Customers shared with the withdrawn Interconnection Customer before the withdrawal of the Interconnection Customer and after the withdrawal of the Interconnection Customer. If that comparison indicates an increase in Network Upgrade costs for an Interconnection Customer, Transmission Provider shall apply the withdrawn Interconnection Customer's Withdrawal Penalty funds to the increased costs each impacted Interconnection Customer in the same Cluster experienced associated with such Network Upgrade(s) in proportion to each Interconnection Customer's increased cost assignment, as determined by Transmission Provider.

3.7.1.2.4 Amending LGIA to Apply Reductions to Interconnection Customer's Assigned Network Upgrade Costs and Associated Financial Security Requirement with Respect to Withdrawals in the Same Cluster

Within 30 Calendar Days of all Interconnection Customers in the same Cluster having: (1) withdrawn or been deemed withdrawn; (2) executed an LGIA; or (3) requested an LGIA to be filed unexecuted, Transmission Provider must perform the calculations described in subsection 3.7.1.2.3(a) of this LGIP and provide such Interconnection Customers with an amended LGIA that provides the reduction in Network Upgrade cost assignment and associated reduction to the Interconnection Customer's financial security requirements, under Article 11.5 of the pro forma LGIA, due from the Interconnection Customer to the Transmission Provider.

Where an Interconnection Customer executes the LGIA (or requests the filing of an unexecuted LGIA) and is later withdrawn or its LGIA is terminated, Transmission Provider must, within 30 Calendar Days of such withdrawal or termination, perform the calculations described in subsection 3.7.1.2.3(b) of this LGIP and provide such Interconnection Customers in the same Cluster with an amended LGIA that provides the reduction in Network Upgrade cost assignment and associated reduction to the Interconnection Customer's financial security requirements, under Article 11.5 of the pro forma LGIA, due from the Interconnection Customer to Transmission Provider.

Any repayment by Transmission Provider to Interconnection Customer under Article 11.4 of the pro forma LGIA of amounts advanced for Network Upgrades after the Generating Facility achieves Commercial Operation shall be limited to the Interconnection Customer's total amount of Network Upgrade costs paid and associated financial security provided to Transmission Provider under Article 11.5 of the pro forma LGIA.

3.7.1.2.5 Final Distribution of Withdrawal Penalty Funds

If Withdrawal Penalty funds remain for the Cluster after the Withdrawal Penalty funds are applied to relevant study costs and net increases in shared cost assignments for

Network Upgrades to remaining Interconnection Customers, Transmission Provider will return any remaining Withdrawal Penalty funds to the withdrawn Interconnection Customers in the same Cluster net of the amount of each withdrawn Interconnection Customer's Withdrawal Penalty funds applied to study costs and net increases in shared cost assignments for Network Upgrades to remaining Interconnection Customers.

3.8 Identification of Contingent Facilities.

Transmission Provider shall post in this section a method for identifying the Contingent Facilities to be provided to Interconnection Customer at the conclusion of the [System Impact]*Cluster* Study and included in Interconnection Customer's Large Generator Interconnection Agreement. The method shall be sufficiently transparent to determine why a specific Contingent Facility was identified and how it relates to the Interconnection Request. Transmission Provider shall also provide, upon request of [the]Interconnection Customer, the estimated Interconnection Facility and/or Network Upgrade costs and estimated in-service completion time of each identified Contingent Facility when this information is readily available and not commercially sensitive.

3.9 Penalties for Failure to Meet Study Deadlines.

(1) Transmission Provider shall be subject to a penalty if it fails to complete a Cluster Study, Cluster Restudy, Interconnection Facilities Study, or Affected Systems Study by the applicable deadline set forth in this LGIP. Transmission Provider must pay the penalty for each late Cluster Study, Cluster Restudy, and Interconnection Facilities Study on a pro rata basis per Interconnection Request to all Interconnection Customer(s) included in the relevant study that did not withdraw, or were not deemed withdrawn, from Transmission Provider's interconnection queue before the missed study deadline. Transmission Provider must pay the penalty for a late Affected Systems Study on a pro rata basis per interconnection request to all Affected System Interconnection Customer(s) included in the relevant Affected System Study that did not withdraw, or were not deemed withdrawn, from the host transmission provider's interconnection queue before the missed study deadline. The study delay penalty for each late study shall be distributed no later than forty-five (45) Calendar Days after the late study has been completed.

(2) For penalties assessed in accordance with this Section, the penalty amount will be equal to: $1,000 per Business Day for delays of Cluster Studies beyond the applicable deadline set forth in this LGIP; $2,000 per Business Day for delays of Cluster Re-Studies beyond the applicable deadline set forth in this LGIP; $2,000 per Business Day for delays of Affected System Studies beyond the applicable deadline set forth in this LGIP; and $2,500 per Business Day for delays of Interconnection Facilities Studies beyond the applicable deadline set forth in this LGIP. The total amount of a penalty assessed under this Section shall not exceed: (a) one hundred percent (100%) of the initial study deposit(s) received for all of the Interconnection Requests in the Cluster for Cluster

Studies and Cluster Restudies; (b) one hundred percent (100%) of the initial study deposit received for the single Interconnection Request in the study for Facilities Studies; and (c) one hundred percent (100%) of the study deposit(s) that Transmission Provider collects for conducting the Affected System Study.

(3) Transmission Provider may appeal to the Commission any penalties imposed under this Section. Any such appeal must be filed no later than forty-five (45) Calendar Days after the late study has been completed. While an appeal to the Commission is pending, Transmission Provider shall remain liable for the penalty, but need not distribute the penalty until forty-five (45) Calendar Days after (1) the deadline for filing a rehearing request has ended, if no requests for rehearing of the appeal have been filed, or (2) the date that any requests for rehearing of the Commission's decision on the appeal are no longer pending before the Commission. The Commission may excuse Transmission Provider from penalties under this Section for good cause.

(4) No penalty will be assessed under this Section where a study is delayed by ten (10) Business Days or less. If the study is delayed by more than ten (10) Business Days, the penalty amount will be calculated from the first Business Day the Transmission Provider misses the applicable study deadline.

(5) If (a) Transmission Provider needs to extend the deadline for a particular study subject to penalties under this Section and (b) all Interconnection Customers or Affected System Interconnection Customers included in the relevant study mutually agree to such an extension, the deadline for that study shall be extended thirty (30) Business Days from the original deadline. In such a scenario, no penalty will be assessed for Transmission Provider missing the original deadline.

(6) No penalties shall be assessed until the third Cluster Study cycle (including any Transitional Cluster Study cycle, but not Transitional Serial Studies) after the Commission-approved effective date of Transmission Provider's filing made in compliance with the Final Rule in Docket No. RM22-14-000.

(7) Transmission Provider must maintain on its OASIS or its public website summary statistics related to penalties assessed under this Section, updated quarterly. For each calendar quarter, Transmission Provider must calculate and post (1) the total amount of penalties assessed under this Section during the previous reporting quarter and (2) the highest penalty assessed under this Section paid to a single Interconnection Customer or Affected System Interconnection Customer during the previous reporting quarter. Transmission Provider must post on its OASIS or its website these penalty amounts for each calendar quarter within thirty (30) Calendar Days of the end of the calendar quarter. Transmission Provider must maintain the quarterly measures posted on its OASIS or its website for three (3) calendar years with the first required posting to be the third Cluster Study cycle (including any Transitional Cluster Study cycle, but not

Transitional Serial Studies) after Transmission Provider transitions to the Cluster Study Process.

Section 4. ***Interconnection Request Evaluation Process.*** **[Queue Position]**

Once an Interconnection Customer has submitted a valid Interconnection Request pursuant to Section 3.4 of this LGIP, such Interconnection Request shall become part of the Transmission Provider's interconnection queue for further processing pursuant to the following procedures.

4.1 ***Queue Position.*** **[General]**

4.1.1 Assignment of Queue Position.

Transmission Provider shall assign a Queue Position *as follows: the Queue Position within the queue shall be assigned* based upon the date and time of receipt of *all items required pursuant to the provisions of Section 3.4 of this LGIP. All Interconnection Requests submitted and validated in a single Cluster Request Window shall be considered equally queued.* [based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.4.3, then Transmission Provider shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 4.4.3.]

[The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued]

4.1.2 Higher Queue Position.

A higher Queue Position assigned to an Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is [lower queued. Transmission Provider may allocate the cost of the common upgrades for clustered Interconnection Requests without regard to Queue Position.]*assigned a lower Queue Position. All requests studied in a single Cluster shall be considered equally queued. Interconnection Customers that are part of Clusters initiated earlier in time than an instant Queue shall be considered to have a higher Queue Position than Interconnection Customers that are part of Clusters initiated later than an instant Queue.*

[**4.2 Clustering.**

At Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.
Clustering shall be implemented on the basis of Queue Position. If Transmission Provider elects to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.]

4.2. General Study Process.

[Clustering Interconnection System Impact Studies]*Interconnection Studies performed within the Cluster Study Process* shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study *and consistent with Good Utility Practice*.

Transmission Provider may use subgroups in the Cluster Study Process. In all instances in which Transmission Provider elects to use subgroups in the cluster study process, Transmission Provider must publish the criteria used to define and determine subgroups on its OASIS or public website.

[The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on Transmission Provider's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.]

4.2.1 Cost Allocation for Interconnection Facilities and Network Upgrades.

(1) For Network Upgrades identified in Cluster Studies, Transmission Provider shall calculate each Interconnection Customer's share of the costs as follows:

(a) Substation Network Upgrades, including all switching stations, shall be allocated per capita to each Generating Facility interconnecting at the same substation.

(b) System Network Upgrades shall be allocated based on the proportional impact of each individual Generating Facility in the Cluster Study on the need for a specific System Network Upgrade. {Transmission Provider shall include in this section a description of how cost for each facility type designated as a network upgrade will be allocated using its proportional impact method.}

(c) An Interconnection Customer that funds Substation Network Upgrades and/or System Network Upgrades shall be entitled to transmission credits as provided in Article 11.4 of the LGIA.

(2) The costs of any needed Interconnection Facilities identified in the Cluster Study Process will be directly assigned to the Interconnection Customer(s) using such facilities. Where Interconnection Customers in the Cluster agree to share Interconnection Facilities, the cost of such Interconnection Facilities shall be allocated based on the number of Generating Facilities sharing use of such Interconnection Facilities on a per capita basis (i.e., on a per Generating Facility basis), unless Parties mutually agree to a different cost sharing arrangement.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications.

Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2*,* or 4.4.5 *of this LGIP*, or are determined not to be Material Modifications pursuant to Section 4.4.3 *of this LGIP*.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider[,] *and* Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection

prior to return of the executed Cluster Study Agreement, [and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable]and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed [Interconnection System Impact]*Cluster* Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project, through either (1) a decrease in plant size or (2) a decrease in Interconnection Service level (consistent with the process described in Section 3.1 *of this LGIP*) accomplished by applying Transmission Provider-approved injection-limiting equipment; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go [to]*in* the [end of the queue]*next Cluster Study Window* for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facilit[y]*ies* Study Agreement to Transmission Provider, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output of the proposed project through either (1) a decrease in plant size (MW) or (2) a decrease in Interconnection Service level (consistent with the process described in Section 3.1) accomplished by applying Transmission Provider-approved injection-limiting equipment; (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer; and (c) a Permissible Technological Advancement for the Large Generating Facility after the submission of the Interconnection Request. Section 4.4.6 specifies a separate technological change procedure including the requisite information and process that will be followed to assess whether the Interconnection Customer's proposed technological advancement under Section 4.4.2(c) is a Material Modification. Section 1 contains a definition of Permissible Technological Advancement.

4.4.3 Prior to making any modification other than those specifically permitted by Sections 4.4.1, 4.4.2, and 4.4.5 *of this LGIP*, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections *3.1.2 or* 4.4 *of this LGIP*[.1, 6.1, 7.2] or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw

the proposed modification or proceed with a new Interconnection Request for such modification. *Transmission Provider shall study the addition of a Generating Facility that includes at least one electric storage resource using operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) that reflect the proposed charging behavior of the Generating Facility as requested by Interconnection Customer, unless Transmission Provider determines that Good Utility Practice, including Applicable Reliability Standards, otherwise requires the use of different operating assumptions.*

{Transmission Providers using fuel-based dispatch assumptions in Interconnection Studies are not required to include Section 4.4.3.1 because it does not apply to them}

4.4.3.1 *Interconnection Customer may request, and Transmission Provider shall evaluate, the addition to the Interconnection Request of a Generating Facility with the same Point of Interconnection indicated in the initial Interconnection Request, if the addition of the Generating Facility does not increase the requested Interconnection Service level. Transmission Provider must evaluate such modifications prior to deeming them a Material Modification, but only if Interconnection Customer submits them prior to the return of the executed Facilities Study Agreement by Interconnection Customer to Transmission Provider. Interconnection Customers requesting that such a modification be evaluated must demonstrate the required Site Control at the time such request is made.*

4.4.4 Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost. *Any such request for modification of the Interconnection Request must be accompanied by any resulting updates to the models described in Attachment A to Appendix 1 of this LGIP.*

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing. *For purposes of this section, the Commercial Operation Date reflected in the initial Interconnection Request shall be used to calculate the permissible extension prior to Interconnection Customer executing an LGIA or requesting that the LGIA be filed unexecuted. After an LGIA is executed or requested to be filed unexecuted, the Commercial Operation Date reflected in the LGIA shall be used to calculate the permissible extension. Such cumulative extensions may not exceed three years including both extensions requested after execution of the LGIA by Interconnection Customer or the filing of an unexecuted*

LGIA by Transmission Provider and those requested prior to execution of the LGIA by Interconnection Customer or the filing of an unexecuted LGIA by Transmission Provider.

4.4.6 Technological Change Procedures

{Insert technological change procedure here}

Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of *the Cluster Study Revisions*[Standard Large Generator Interconnection Procedures]

5.1 *Procedures for Transitioning to the Cluster Study Process* [Queue Position for Pending Requests.]

5.1.1

[Any Interconnection Customer assigned a Queue Position prior to the effective date of this LGIP shall retain that Queue Position.]
Any Interconnection Customer assigned a Queue Position as of thirty (30) Calendar Days after {Transmission Provider to insert filing date} (the filing date of this LGIP) shall retain that Queue Position subject to the requirements in Sections 5.1.1.1 and 5.1.1.2 of this LGIP. Any Interconnection Customer that fails to meet these requirements shall have its Interconnection Request deemed withdrawn by Transmission Provider pursuant to Section 3.7 of this LGIP. In such case, Transmission Provider shall not assess the Interconnection Customer any Withdrawal Penalty.

Any Interconnection Customer that has received a final Interconnection Facilities Study Report before the commencement of the studies under the transition process set forth in this section shall be tendered an LGIA pursuant to Section 11 of this LGIP, and shall not be required to enter this transition process.

5.1.1.1 *Transitional Serial Study.*

[If an Interconnection Study Agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.]
An Interconnection Customer that has been tendered an Interconnection Facilities Study Agreement as of thirty (30) Calendar Days after {Transmission Provider to insert filing date} (the filing date of this LGIP) may opt to proceed with an Interconnection Facilities Study. Transmission Provider shall tender each eligible Interconnection Customer a Transitional Serial Interconnection Facilities Study Agreement, in the form of Appendix 8 to this LGIP, no later than the Commission-approved effective date of this LGIP. Transmission Provider shall proceed with the Interconnection Facilities Study, provided

that the Interconnection Customer: (1) meets each of the following requirements; and (2) executes the Transitional Serial Interconnection Facilities Study Agreement within sixty (60) Calendar Days of the Commission-approved effective date of this LGIP. If an eligible Interconnection Customer does not meet these requirements, its Interconnection Request shall be deemed withdrawn without penalty. Transmission Provider must commence the Transitional Serial Interconnection Facilities Study at the conclusion of this sixty (60) Calendar Day period. Transitional Serial Interconnection Facilities Study costs shall be allocated according to the method described in Section 13.3 of this LGIP.

All of the following must be included when an Interconnection Customer returns the Transitional Serial Interconnection Facilities Study Agreement:

(1) A deposit equal to one hundred percent (100%) of the costs identified for Transmission Provider's Interconnection Facilities and Network Upgrades in Interconnection Customer's system impact study report. If Interconnection Customer does not withdraw, the deposit shall be trued up to actual costs once they are known and applied to future construction costs described in Interconnection Customer's eventual LGIA. Any amounts in excess of the actual construction costs shall be returned to Interconnection Customer within *thirty (30) Calendar Days of the issuance of a final invoice for construction costs, in accordance with Article 12.2 of the pro forma LGIA. If Interconnection Customer withdraws or otherwise does not reach Commercial Operation, Transmission Provider shall refund the remaining deposit after the final invoice for study costs and Withdrawal Penalty is settled. The deposit shall be in the form of an irrevocable letter of credit or cash where cash deposits shall be treated according to Section 3.7 of this LGIP.*

(2) Exclusive Site Control for 100% of the proposed Generating Facility.

Transmission Provider shall conduct each Transitional Serial Interconnection Facilities Study and issue the associated Transitional Serial Interconnection Facilities Study Report within one hundred fifty (150) Calendar Days of the Commission-approved effective date of this LGIP.

After Transmission Provider issues each Transitional Interconnection Facilities Study Report, Interconnection Customer shall proceed pursuant to Section 11 of this LGIP. If Interconnection Customer withdraws its Interconnection Request or if Interconnection Customer's Generating Facility otherwise does not reach Commercial Operation, a Withdrawal Penalty shall be imposed on Interconnection Customer equal to nine (9) times Interconnection Customer's total study cost incurred since entering the Transmission Provider's interconnection queue (including the cost of studies conducted under Section 5 of this LGIP).

5.1.1.2 *Transitional Cluster Study.*

[If an Interconnection Study Agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study Agreement prior to the effective date of the LGIP, Transmission Provider must offer Interconnection Customer the option of either continuing under Transmission Provider's existing interconnection study process or going forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies Agreement) in accordance with this LGIP.]

An Interconnection Customer with an assigned Queue Position as of thirty (30) Calendar Days after {Transmission Provider to insert filing date} (the filing date of this LGIP) may opt to proceed with a Transitional Cluster Study. Transmission Provider shall tender each eligible Interconnection Customer a Transitional Cluster Study Agreement, in the form of Appendix 7 to this LGIP, no later than the Commission-approved effective date of this LGIP. Transmission Provider shall proceed with the Transitional Cluster Study that includes each Interconnection Customer that: (1) meets each of the following requirements listed as (1) – (3) in this section; and (2) executes the Transitional Cluster Study Agreement within sixty (60) Calendar Days of the Commission-approved effective date of this LGIP. All Interconnection Requests that enter the Transitional Cluster Study shall be considered to have an equal Queue Position that is lower than Interconnection Customer(s) proceeding with Transitional Serial Interconnection Facilities Study. If an eligible Interconnection Customer does not meet these requirements, its Interconnection Request shall be deemed withdrawn without penalty. Transmission Provider must commence the Transitional Cluster Study at the conclusion of this sixty (60) Calendar Day period. All identified Transmission Provider's Interconnection Facilities and Network Upgrade costs shall be allocated according to Section 4.2.1 of this LGIP. Transitional Cluster Study costs shall be allocated according to the method described in Section 13.3 of this LGIP.

Interconnection Customer may make a one-time extension to its requested Commercial Operation Date upon entry into the Transitional Cluster Study, where any such extension shall not result in a Commercial Operation Date later than December 31, 2027.

All of the following must be included when an Interconnection Customer returns the Transitional Cluster Study Agreement:

(1) A selection of either Energy Resource Interconnection Service or Network Resource Interconnection Service.

(2) A deposit of five million dollars ($5,000,000) in the form of an irrevocable letter of credit or cash where cash deposits will be treated according to Section 3.7 of this LGIP. If Interconnection Customer does not withdraw, the deposit shall be reconciled with and applied towards future construction costs described in the LGIA. Any amounts in excess of the actual construction costs shall be returned to Interconnection Customer within thirty (30) Calendar Days of the issuance of a final invoice for construction costs, in accordance with Article 12.2 of the pro forma LGIA. If Interconnection Customer withdraws or otherwise does not reach Commercial Operation, Transmission Provider must refund the remaining deposit once the final invoice for study costs and Withdrawal Penalty is settled.

(3) Exclusive Site Control for 100% of the proposed Generating Facility.

Transmission Provider shall conduct the Transitional Cluster Study and issue both an associated interim Transitional Cluster Study Report and an associated final Transitional Cluster Study Report. The interim Transitional Cluster Study Report shall provide the following information:

- *identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;*
- *identification of any thermal overload or voltage limit violations resulting from the interconnection;*
- *identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and*
- *Transmission Provider's Interconnection Facilities and Network Upgrades that are expected to be required as a result of the Interconnection Request(s) and a non-binding, good faith estimate of cost responsibility and a non-binding, good faith estimated time to construct.*

In addition to the information provided in the interim Transitional Cluster Study Report, the final Transitional Cluster Study Report shall provide a description of, estimated cost of, and schedule for construction of the Transmission Provider's Interconnection Facilities and Network Upgrades required to interconnect the Generating Facility to the Transmission System that resolve issues identified in the interim Transitional Cluster Study Report.

The interim and final Transitional Cluster Study Reports shall be issued within three hundred (300) and three hundred sixty (360) Calendar Days of the Commission-approved effective date of this LGIP, respectively, and shall be posted on Transmission Provider's OASIS consistent with the posting of other study results pursuant to Section 3.5.1 of this LGIP. Interconnection Customer shall have thirty (30) Calendar Days to comment on the interim Transitional Cluster Study Report, once it has been received.

After Transmission Provider issues the final Transitional Cluster Study Report, Interconnection Customer shall proceed pursuant to Section 11 of this LGIP. If Interconnection Customer withdraws its Interconnection Request or if Interconnection Customer's Generating Facility otherwise does not reach Commercial Operation, a Withdrawal Penalty will be imposed om Interconnection Customer equal to nine (9) times Interconnection Customer's total study cost incurred since entering the Transmission Provider's interconnection queue (including the cost of studies conducted under Section 5 of this LGIP).

[**5.1.1.3** If an LGIA has been submitted to FERC for approval before the effective date of the LGIP, then the LGIA would be grandfathered.

5.1.2 Transition Period.

To the extent necessary, Transmission Provider and Interconnection Customers with an outstanding request (i.e., an Interconnection Request for which an LGIA has not been submitted to FERC for approval as of the effective date of this LGIP) shall transition to this LGIP within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding request" herein shall mean any Interconnection Request, on the effective date of this LGIP: (i) that has been submitted but not yet accepted by Transmission Provider; (ii) where the related interconnection agreement has not yet been submitted to FERC for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding request as of the effective date of this LGIP may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by Transmission Provider to the extent consistent with the intent and process provided for under this LGIP.]

5.2 New Transmission Provider.

If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this LGIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If Transmission Provider has tendered a draft LGIA to Interconnection

Customer but Interconnection Customer has not either executed the LGIA or requested the filing of an unexecuted LGIA with FERC, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.

Section 6. Interconnection *Information Access*[Feasibility Study]

6.1 Publicly Posted Interconnection Information.

Transmission Provider shall maintain and make publicly available: (1) an interactive visual representation of the estimated incremental injection capacity (in megawatts) available at each point of interconnection in Transmission Provider's footprint under N-1 conditions, and (2) a table of metrics concerning the estimated impact of a potential Generating Facility on Transmission Provider's Transmission System based on a user-specified addition of a particular number of megawatts at a particular voltage level at a particular point of interconnection. At a minimum, for each transmission facility impacted by the user-specified megawatt addition, the following information will be provided in the table: (1) the distribution factor; (2) the megawatt impact (based on the megawatt values of the proposed Generating Facility and the distribution factor); (3) the percentage impact on each impacted transmission facility (based on the megawatt values of the proposed Generating Facility and the facility rating); (4) the percentage of power flow on each impacted transmission facility before the injection of the proposed project; (5) the percentage power flow on each impacted transmission facility after the injection of the proposed Generating Facility. These metrics must be calculated based on the power flow model of the Transmission System with the transfer simulated from each point of interconnection to the whole Transmission Provider's footprint (to approximate Network Resource Interconnection Service), and with the incremental capacity at each point of interconnection decremented by the existing and queued Generating Facilities (based on the existing or requested interconnection service limit of the generation). These metrics must be updated within thirty (30) Calendar Days after the completion of each Cluster Study and Cluster Restudy. This information must be publicly posted, without a password or a fee. The website will define all underlying assumptions, including the name of the most recent Cluster Study or Restudy used in the Base Case.

[6.1 Interconnection Feasibility Study Agreement.

Simultaneously with the acknowledgement of a valid Interconnection Request Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall*:* specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Within five

(5) Business Days following Transmission Provider's receipt of such designation, Transmission Provider shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by Transmission Provider, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement along with a $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and Re-studies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.4.4, shall be the substitute.

If Interconnection Customer and Transmission Provider agree to forgo the Interconnection Feasibility Study, Transmission Provider will initiate an Interconnection System Impact Study under Section 7 of this LGIP and apply the $10,000 deposit towards the Interconnection System Impact Study.]

[6.2 Scope of Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System.

The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list

of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.]

[6.3 Interconnection Feasibility Study Procedures.

Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after Transmission Provider receives the fully executed Interconnection Feasibility Study Agreement. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 13.1.

Transmission Provider shall study the Interconnection Request at the level of service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns.]

[6.3.1 Meeting with Transmission Provider.

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.]

[6.4 Re-Study.

If Re-Study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 6.1 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take not longer than forty-five (45) Calendar Days from the date of the notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.]

Section 7. [Interconnection System Impact]*Cluster* Study

7.1 [Interconnection System Impact]*Cluster* Study Agreement.

[Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.4.4, simultaneously with the delivery of the Interconnection Feasibility Study to Interconnection Customer]*No later than five (5) Business Days after the close of a Cluster Request Window*, Transmission Provider shall [provide]*tender* to *each* Interconnection Customer [an]*that submitted a valid* Interconnection[System Impact] *Request a Cluster* Study Agreement in the form of Appendix *2*[3] to this LGIP. The [Interconnection System Impact]*Cluster* Study Agreement shall [provide that]*require* Interconnection Customer [shall]*to* compensate Transmission Provider for the actual cost of the [Interconnection System Impact Study.]*Cluster Study pursuant to Section 13.3 of this LGIP. The specifications, assumptions, or other provisions in the appendices of the Cluster Study Agreement provided pursuant to Section 7.1 of this LGIP shall be subject to change by Transmission Provider following the conclusion of the Scoping Meeting.* [Within three (3) Business Days following the Interconnection Feasibility Study results meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.]

7.2 Execution of [Interconnection System Impact]*Cluster* Study Agreement.

Interconnection Customer shall execute the [Interconnection System Impact]*Cluster* Study Agreement and deliver the executed [Interconnection System Impact]*Cluster* Study Agreement to Transmission Provider no later than [thirty (30) Calendar Days after its receipt along with demonstration of Site Control, and a $50,000 deposit]*the close of the Customer Engagement Window.*

If Interconnection Customer does not provide all [such] *required* technical data when it delivers the [Interconnection System Impact]*Cluster* Study Agreement, Transmission Provider shall notify Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed [Interconnection System Impact]*Cluster* Study Agreement and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed [Interconnection System Impact]*Cluster* Study Agreement or *Study D*eposit.

[If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection

specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.4.4, shall be the substitute.]

7.3 Scope of [Interconnection System Impact]*Cluster* Study.

The [Interconnection System Impact]*Cluster* Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The [Interconnection System Impact]*Cluster* Study will consider the Base Case as well as all Generating Facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the [Interconnection System Impact]*Cluster* Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

For purposes of determining necessary Interconnection Facilities and Network Upgrades, the Cluster Study shall use the level of Interconnection Service requested by Interconnection Customers in the Cluster, except where the Transmission Provider otherwise determines that it must study the full Generating Facility Capacity due to safety or reliability concerns.

The [Interconnection System Impact]*Cluster* Study will consist of [a short circuit analysis, a]*power flow*, stability[analysis, and a power flow analysis. The Interconnection System Impact Study]*, and short circuit analyses, the results of which are documented in a single Cluster Study Report, as applicable. At the conclusion of the Cluster Study, Transmission Provider shall issue a Cluster Study Report. The Cluster Study Report* will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. [For purposes of determining necessary]*The Cluster Study Report shall identify the* Interconnection Facilities and Network Upgrades [, the System Impact Study shall consider the level of Interconnection Service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns.]*expected to be required to reliably interconnect the Generating Facilities in that Cluster Study at the requested Interconnection Service level and shall provide non-binding cost estimates for required*

Network Upgrades. The Cluster Study Report shall identify each Interconnection Customer's estimated allocated costs for Interconnection Facilities and Network Upgrades pursuant to the method in Section 4.2.1 of this LGIP. Transmission Provider shall hold an open stakeholder meeting pursuant to Section 7.4 of this LGIP.

For purposes of determining necessary Interconnection Facilities and Network Upgrades, the Cluster Study shall use operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) that reflect the proposed charging behavior of a Generating Facility that includes at least one electric storage resource as requested by Interconnection Customer, unless Transmission Provider determines that Good Utility Practice, including Applicable Reliability Standards, otherwise requires the use of different operating assumptions. Transmission Provider may require the inclusion of control technologies sufficient to limit the operation of the Generating Facility per the operating assumptions as set forth in the Interconnection Request and to respond to dispatch instructions by Transmission Provider. As determined by Transmission Provider, Interconnection Customer may be subject to testing and validation of those control technologies consistent with Article 6 of the LGIA.

[The Interconnection System Impact Study]*The Cluster Study Report* will provide a list of facilities that are required as a result of the Interconnection [Request]*Requests within the Cluster* and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

Upon issuance of a Cluster Study Report, or Cluster Restudy Report, if any, Transmission Provider shall simultaneously tender a draft Interconnection Facilities Study Agreement to each Interconnection Customer within the Cluster, subject to the conditions in Section 8.1 of this LGIP.

The Cluster Study shall evaluate the use of static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, and tower lifting. Transmission Provider shall determine whether the above technologies should be used, consistent with Good Utility Practice and other applicable regulatory requirements. Transmission Provider shall include an explanation of the results of the Transmission Provider's evaluation for each technology in the Cluster Study Report.

7.4 [Interconnection System Impact]*Cluster* Study Procedures.

Transmission Provider shall coordinate the [Interconnection System Impact]*Cluster* Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.6 [above]*of this LGIP*. Transmission Provider shall utilize existing studies to the extent practicable when it performs the [study]*Cluster Study. Interconnection*

Requests for a Cluster Study may be submitted only within the Cluster Request Window and Transmission Provider shall [use Reasonable Efforts to complete the Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Interconnection System Impact Study Agreement or notification to proceed, study payment, and technical data. If Transmission Provider uses Clustering, Transmission Provider shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within ninety (90) Calendar Days after the close of the Queue Cluster Window.]*initiate the Cluster Study process pursuant to Section 7 of this LGIP.*

Transmission Provider shall complete the Cluster Study within one hundred fifty (150) Calendar Days of the close of the Customer Engagement Window.

Within ten (10) Business Days of simultaneously furnishing a Cluster Study Report to each Interconnection Customer within the Cluster and posting such report on OASIS, Transmission Provider shall convene a Cluster Study Report Meeting.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the [Interconnection System Impact]*Cluster* Study, Transmission Provider shall notify Interconnection Customer*s* as to the schedule status of the [Interconnection System Impact]*Cluster* Study. If Transmission Provider is unable to complete the [Interconnection System Impact]*Cluster* Study within the time period, it shall notify Interconnection Customer*s* and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide *to* Interconnection Customer*s* all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the [Interconnection System Impact]*Cluster* Study, subject to confidentiality arrangements consistent with Section 13.1 *of this LGIP*.

7.5 Cluster Study Restudies.

(1) Within twenty (20) Calendar Days after the Cluster Study Report Meeting, Interconnection Customer must provide the following:

(a) Demonstration of continued Site Control pursuant to Section 3.4.2(iii) of this LGIP; and

(b) An additional deposit that brings the total Commercial Readiness Deposit submitted to Transmission Provider to five percent (5%) of the Interconnection Customer's Network Upgrade cost assignment identified in the Cluster Study in the form of an irrevocable letter of credit or cash. Transmission Provider shall refund the deposit to Interconnection Customer upon withdrawal in accordance with Section 3.7 of this LGIP.

Interconnection Customer shall promptly inform Transmission Provider of any material change to Interconnection Customer's demonstration of Site Control under Section 3.4.2(iii) of this LGIP. Upon Transmission Provider determining that Interconnection Customer no longer satisfies the Site Control requirement, Transmission Provider shall notify Interconnection Customer. Within ten (10) Business Days of such notification, Interconnection Customer must demonstrate compliance with the applicable requirement subject to Transmission Provider's approval, not to be unreasonably withheld. Absent such demonstration, Transmission Provider shall deem the subject Interconnection Request withdrawn pursuant to Section 3.7 of this LGIP.

(2) If no Interconnection Customer withdraws from the Cluster after completion of the Cluster Study or Cluster Restudy or is deemed withdrawn pursuant to Section 3.7 of this LGIP after completion of the Cluster Study or Cluster Restudy, Transmission Provider shall notify Interconnection Customers in the Cluster that a Cluster Restudy is not required.

(3) If one or more Interconnection Customers withdraw from the Cluster or are deemed withdrawn pursuant to Section 3.7 of this LGIP, Transmission Provider shall determine if a Cluster Restudy is necessary within thirty (30) Calendar Days after the Cluster Study Report Meeting. If Transmission Provider determines a Cluster Restudy is not necessary, Transmission Provider shall notify Interconnection Customers in the Cluster that a Cluster Restudy is not required and Transmission Provider shall provide an updated Cluster Study Report within thirty (30) Calendar Days of such determination.

(4) If one or more Interconnection Customers withdraws from the Cluster or is deemed withdrawn pursuant to Section 3.7 of this LGIP, and Transmission Provider determines a Cluster Restudy is necessary as a result, Transmission Provider shall notify Interconnection Customers in the Cluster and post on OASIS that a Cluster Restudy is required within thirty (30) Calendar Days after the Cluster Study Report Meeting. Transmission Provider shall continue with such restudies until Transmission Provider determines that no further restudies are required. If an Interconnection Customer withdraws or is deemed withdrawn pursuant to Section 3.7 of this LGIP during the Interconnection Facilities Study, or after other Interconnection Customers in the same Cluster have executed LGIAs, or requested that unexecuted LGIAs be filed, and Transmission Provider determines a Cluster Restudy is necessary, the Cluster shall be restudied.

(5) The scope of any Cluster Restudy shall be consistent with the scope of an initial Cluster Study pursuant to Section 7.3 of this LGIP. Transmission Provider shall complete the Cluster Restudy within one hundred fifty (150) Calendar Days of the Transmission Provider informing the Interconnection Customers in the cluster that restudy is needed. The results of the Cluster Restudy shall be combined into a single

report (Cluster Restudy Report). Transmission Provider shall hold a meeting with the Interconnection Customers in the cluster (Cluster Restudy Report Meeting) within ten (10) Business Days of simultaneously furnishing the Cluster Restudy Report to each Interconnection Customer in the Cluster Restudy and publishing the Cluster Restudy Report on OASIS.

If additional restudies are required, Interconnection Customer and Transmission Provider shall follow the procedures of this Section 7.5 of this LGIP until such time that Transmission Provider determines that no further restudies are required. Transmission Provider shall notify each Interconnection Customer within the Cluster when no further restudies are required.

[**Meeting with Transmission Provider.**

Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study.

If Re-Study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to 4.4, or re-designation of the Point of Interconnection pursuant to Section 7.2 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.]

Section 8. Interconnection Facilities Study

8.1 Interconnection Facilities Study Agreement.

Simultaneously with the delivery of the [Interconnection System Impact Study to Interconnection Customer] *Cluster Study Report, or Cluster Restudy Report if applicable*, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix *3*[4] to this LGIP. [The Interconnection Facilities Study Agreement shall provide that] Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Within five (5) Business Days following the *Cluster Report Meeting or Cluster Restudy Report Meeting if applicable,*[Interconnection System Impact Study results meeting], Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study.

Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider within thirty (30) Calendar Days after its receipt, together with[the]*:*

(1) any required technical data[and the greater of $100,000 or Interconnection Customer's portion of the estimated monthly cost of conducting the Interconnection Facilities Study.]*;*

(2) Demonstration of one-hundred percent (100%) Site Control or demonstration of a regulatory limitation and applicable deposit in lieu of Site Control provided to the Transmission Provider in accordance with section 3.4.2 of this LGIP; and

(3) An additional deposit that brings the total Commercial Readiness Deposit submitted to the Transmission Provider to ten percent (10%) of the Interconnection Customer's Network Upgrade cost assignment identified in the Cluster Study or Cluster Restudy, if applicable, in the form of an irrevocable letter of credit or cash. Transmission Provider shall refund the deposit to Interconnection Customer upon withdrawal in accordance with Section 3.7 of this LGIP.

Interconnection Customer shall promptly inform Transmission Provider of any material change to Interconnection Customer's demonstration of Site Control under Section 3.4.2(iii) of this LGIP. Upon Transmission Provider determining separately that Interconnection Customer no longer satisfies the Site Control requirement, Transmission Provider shall notify Interconnection Customer. Within ten (10) Business Days of such notification, Interconnection Customer must demonstrate compliance with the applicable requirement subject to Transmission Provider's approval, not to be unreasonably withheld. Absent such demonstration, Transmission Provider shall deem the subject Interconnection Request withdrawn pursuant to Section 3.7 of this LGIP.

[**8.1.1** Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.]

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study *shall be specific to each Interconnection Request and performed on an individual, i.e., non-clustered, basis. The Interconnection Facilities Study* shall specify and *provide a non-binding* estimate *of* the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the [Interconnection System Impact Study]*Cluster Study Report (and any associated restudies)* in accordance with Good Utility Practice to physically and electrically connect

the Interconnection [Facility]*Facilities* to the Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The *Interconnection* Facilities Study will also identify any potential control equipment for [requests for]*(1)* requests for Interconnection Service that are lower than the Generating Facility Capacity[.]*, and/or (2) requests to study a Generating Facility that includes at least one electric storage resource using operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) that reflect its proposed charging behavior, as requested by Interconnection Customer, unless Transmission Provider determines that Good Utility Practice, including Applicable Reliability Standards, otherwise require the use of different operating assumptions.*

8.3 Interconnection Facilities Study Procedures.

Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 3.6 *of this LGIP*. Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. Transmission Provider shall [use Reasonable Efforts to]complete the study and issue a draft Interconnection Facilities Study [r]*R*eport to Interconnection Customer within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: ninety (90) Calendar Days *after receipt of an executed Interconnection Facilities Study Agreement*, with no more than a +/- 20 percent cost estimate contained in the report; or one hundred eighty (180) Calendar Days, if Interconnection Customer requests a +/- 10 percent cost estimate.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study [r]*R*eport within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

Interconnection Customer may, within thirty (30) Calendar Days after receipt of the draft *Interconnection Facilities Study* [r]*R*eport, provide written comments to Transmission Provider, which Transmission Provider shall include in *completing* the final *Interconnection Facilities Study* [r]*R*eport. Transmission Provider shall issue the final Interconnection Facilities Study [r]*R*eport within fifteen (15) Business Days of receiving

Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen[-day] *(15) Business Day* period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities *Study* Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1 *of this LGIP*.

8.4 Meeting with Transmission Provider.

Within ten (10) Business Days of providing a draft Interconnection Facilities Study [r]*R*eport to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

8.5 [Re-Study]*Restudy*.

If [Re-Study]*Restudy* of the Interconnection Facilities Study is required due to a higher *or equally* queued project [dropping out of] *withdrawing from* the queue or a modification of a higher *or equally* queued project pursuant to Section 4.4 *of this LGIP*, Transmission Provider shall so notify Interconnection Customer in writing. [Such]*Transmission Provider shall ensure that such* [Re-Study]*Restudy* [shall]take*s* no longer than sixty (60) Calendar Days from the date of notice. *Except as provided in Section 3.7 of this LGIP in the case of withdrawing Interconnection Customers, any* cost of [Re-Study]*Restudy* shall be borne by [the]Interconnection Customer being [re-studied]*restudied*.

Section 9 [Engineering & Procurement ('E&P') Agreement]*Affected System Study*.

9.1 Applicability.

This Section 9 outlines the duties of Transmission Provider when it receives notification that an Affected System Interconnection Customer's proposed interconnection to its host transmission provider may impact Transmission Provider's Transmission System.

9.2 Response to Initial Notification

When Transmission Provider receives notification that an Affected System Interconnection Customer's proposed interconnection to its host transmission provider may impact Transmission Provider's Transmission System, Transmission Provider must respond in writing within twenty (20) Business Days whether it intends to conduct an Affected System Study.

By fifteen (15) Business Days after the Transmission Provider responds with its affirmative intent to conduct an Affected System Study, Transmission Provider shall share with Affected System Interconnection Customer(s) and the Affected System Interconnection Customer's host transmission provider a non-binding good faith estimate of the cost and the schedule to complete the Affected System Study.

9.3 Affected System Queue Position.

Transmission Provider must assign an Affected System Queue Position to Affected System Interconnection Customer(s) that require(s) an Affected System Study. Such Affected System Queue Position shall be assigned based upon the date of execution of the Affected System Study Agreement. Relative to the Transmission Provider's Interconnection Customers, this Affected System Queue Position shall be higher-queued than any Cluster that has not yet received its Cluster Study Report and shall be lower-queued than any Cluster that has already received its Cluster Study Report. Consistent with Section 9.7 of this LGIP, Transmission Provider shall study the Affected System Interconnection Customer(s) via Clustering, and all Affected System Interconnection Customers studied in the same Cluster under Section 9.7 shall be equally queued. For Affected System Interconnection Customers that are equally queued, the Affected System Queue Position shall have no bearing on the assignment of Affected System Network Upgrades identified in the applicable Affected System Study. The costs of the Affected System Network Upgrades shall be allocated among the Affected System Interconnection Customers in accordance with Section 9.9 of this LGIP.

9.4 Affected System Study Agreement/Multiparty Affected System Study Agreement.

Unless otherwise agreed, Transmission Provider shall provide to Affected System Interconnection Customer(s) an Affected System Study Agreement/Multiparty Affected System Study Agreement, in the form of Appendix 9 or Appendix 10 to this LGIP, as applicable, within ten (10) Business Days of Transmission Provider sharing the schedule for the Affected System Study per Section 9.2 of this LGIP.

Upon Affected System Interconnection Customer(s)' receipt of the Affected System Study Report, Affected System Interconnection Customer(s) shall compensate Transmission Provider for the actual cost of the Affected System Study. Any difference between the study deposit and the actual cost of the Affected System Study shall be paid by or refunded to the Affected System Interconnection Customer(s). Any invoices for the Affected System Study shall include a detailed and itemized accounting of the cost of the study. Affected System Interconnection Customer(s) shall pay any excess costs beyond the already-paid Affected System Study deposit or be reimbursed for any costs collected over the actual cost of the Affected System Study within thirty (30) Calendar Days of receipt of an invoice thereof. If Affected System Interconnection Customer(s) fail to pay such undisputed costs within the time allotted, it shall lose its Affected System Queue

Position. Transmission Provider shall notify Affected System Interconnection Customer's host transmission provider of such failure to pay.

9.5 Execution of Affected System Study Agreement/Multiparty Affected System Study Agreement.

Affected System Interconnection Customer(s) shall execute the Affected System Study Agreement/Multiparty Affected System Study Agreement, deliver the executed Affected System Study Agreement/Multiparty Affected System Study Agreement to Transmission Provider, and provide the Affected System Study deposit within ten (10) Business Days of receipt.

If Affected System Interconnection Customer does not provide all required technical data when it delivers the Affected System Study Agreement/Multiparty Affected System Study Agreement, Transmission Provider shall notify the deficient Affected System Interconnection Customer, as well as the host transmission provider with which Affected System Interconnection Customer seeks to interconnect, of the deficiency within five (5) Business Days of the receipt of the executed Affected System Study Agreement/Multiparty Affected System Study Agreement and the deficient Affected System Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice: provided, however, that such deficiency does not include failure to deliver the executed Affected System Study Agreement/Multiparty Affected System Study Agreement or deposit for the Affected System Study Agreement/Multiparty Affected System Study Agreement. If Affected System Interconnection Customer does not cure the deficiency or fails to execute the Affected System Study Agreement/Multiparty Affected System Study Agreement or provide the deposit, the Affected System Interconnection Customer shall lose its Affected System Queue Position.

9.6 Scope of Affected System Study.

The Affected System Study shall evaluate the impact that any Affected System Interconnection Customer's proposed interconnection to another transmission provider's transmission system will have on the reliability of Transmission Provider's Transmission System. The Affected System Study shall consider the Base Case as well as all Generating Facilities (and with respect to (iii) below, any identified Affected System Network Upgrades associated with such higher-queued Interconnection Request) that, on the date the Affected System Study is commenced: (i) are directly interconnected to Transmission Provider's Transmission System; (ii) are directly interconnected to another transmission provider's transmission system and may have an impact on Affected System Interconnection Customer's interconnection request; (iii) have a pending higher-queued Interconnection Request to interconnect to Transmission Provider's Transmission System; and (iv) have no queue position but have executed an LGIA or requested that an

unexecuted LGIA be filed with FERC. Transmission Provider has no obligation to study impacts of Affected System Interconnection Customers of which it is not notified.

The Affected System Study shall consist of a power flow, stability, and short circuit analysis. The Affected System Study will: state the assumptions upon which it is based; state the results of the analyses; and provide the potential impediments to Affected System Interconnection Customer's receipt if interconnection service on its host transmission provider's transmission system, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. For purposes of determining necessary Affected System Network Upgrades, the Affected System Study shall consider the level of interconnection service requested in megawatts by Affected System Interconnection Customer, unless otherwise required to study the full generating facility capacity due to safety or reliability concerns. The Affected System Study shall provide a list of facilities that are required as a result of Affected System Interconnection Customer's proposed interconnection to another transmission provider's system, a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct. The Affected System Study may consist of a system impact study, a facilities study, or some combination thereof.

9.7 Affected System Study Procedures.

Transmission Provider shall use Clustering in conducting the Affected System Study and shall use existing studies to the extent practicable, when multiple Affected System Interconnection Customers that are part of a single Cluster may cause the need for Affected System Network Upgrades. Transmission Provider shall complete the Affected System Study and provide the Affected System Study Report to Affected System Interconnection Customer(s) and the host transmission provider with whom interconnection has been requested within one hundred fifty (150) Calendar Days after the receipt of the Affected System Study Agreement and deposit.

At the request of Affected System Interconnection Customer, Transmission Provider shall notify Affected System Interconnection Customer as to the status of the Affected System Study. If Transmission Provider is unable to complete the Affected System Study within the requisite time period, it shall notify Affected System Interconnection Customer(s), as well as the transmission provider with which Affected System Interconnection Customer seeks to interconnect, and shall provide an estimated completion date with an explanation of the reasons why additional time is required. If Transmission Provider does not meet the deadlines in this section, Transmission Provider shall be subject to the financial penalties as described in Section 3.9 of this LGIP. Upon request, Transmission Provider shall provide Affected System Interconnection Customer(s) with all supporting documentation, workpapers and relevant power flow, short circuit and stability

databases for the Affected System Study, subject to confidentiality arrangements consistent with Section 13.1 of this LGIP.

Transmission Provider must study an Affected System Interconnection Customer using the Energy Resource Interconnection Service modeling standard used for Interconnection Requests on its own Transmission System, regardless of the level of interconnection service that Affected System Interconnection Customer is seeking from the host transmission provider with whom it seeks to interconnect.

9.8 Meeting with Transmission Provider.

Within ten (10) Business Days of providing the Affected System Study Report to Affected System Interconnection Customer(s), Transmission Provider and Affected System Interconnection Customer(s) shall meet to discuss the results of the Affected System Study.

9.9 Affected System Cost Allocation.

Transmission Provider shall allocate Affected System Network Upgrade costs identified during the Affected System Study to Affected System Interconnection Customer(s) using a proportional impact method, consistent with Section 4.2.1(1)(b) of this LGIP.

9.10 Tender of Affected Systems Facilities Construction Agreement/Multiparty Affected System Facilities Construction Agreement.

Transmission Provider shall tender to Affected System Interconnection Customer(s) an Affected System Facilities Construction Agreement/Multiparty Affected System Facilities Construction Agreement, as applicable, in the form of Appendix 11 or 12 to this LGIP, within thirty (30) Calendar Days of providing the Affected System Study Report. Within ten (10) Business Days of the receipt of the Affected System Facilities Construction Agreement/Multiparty Affected System Facilities Construction Agreement, the Affected System Interconnection Customer(s) must execute the agreement or request the agreement to be filed unexecuted with FERC. Transmission Provider shall execute the agreement or file the agreement unexecuted within five (5) Business Days after receiving direction from Affected System Interconnection Customer(s). Affected System Interconnection Customer's failure to execute the Affected System Facilities Construction Agreement/Multiparty Affected System Facilities Construction Agreement, or failure to request the agreement to be filed unexecuted with FERC, shall result in the loss of its Affected System Queue Position.

9.11 Restudy.

If restudy of the Affected System Study is required, Transmission Provider shall notify Affected System Interconnection Customer(s) in writing within thirty (30) Calendar Days of discovery of the need for restudy. Such restudy shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of restudy shall be borne by the Affected System Interconnection Customer(s) being restudied.

[Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Provider shall offer the Interconnection Customer, an E&P Agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect: (i) to take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.]

Section 10. Optional Interconnection Study

10.1 Optional Interconnection Study Agreement.

On or after the date when Interconnection Customer receives [Interconnection System Impact Study] *Cluster Study* results, Interconnection Customer may request, and Transmission Provider shall perform a reasonable number of Optional Studies. The

request shall describe the assumptions that Interconnection Customer wishes Transmission Provider to study within the scope described in Section 10.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection Study, Transmission Provider shall provide to Interconnection Customer an Optional Interconnection Study Agreement in the form of Appendix *4*[5].

The Optional Interconnection Study Agreement shall: (i) specify the technical data that Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify Interconnection Customer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) Transmission Provider's estimate of the cost of the Optional Interconnection Study. To the extent known by Transmission Provider, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, Transmission Provider shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to Transmission Provider.

10.2 Scope of Optional Interconnection Study.

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. Transmission Provider shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. Transmission Provider shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures.

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to Transmission Provider within ten (10) Business Days of Interconnection Customer receipt of the Optional

Interconnection Study Agreement. Transmission Provider shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If Transmission Provider is unable to complete the Optional Interconnection Study within such time period, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to Transmission Provider or refunded to Interconnection Customer, as appropriate. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with Section 13.1.

Section 11. Standard Large Generator Interconnection Agreement (LGIA)

11.1 Tender.

Interconnection Customer shall tender comments on the draft Interconnection Facilities Study Report within thirty (30) Calendar Days of receipt of the report. Within thirty (30) Calendar Days after the comments are submitted *or after Interconnection Customer notifies Transmission Provider that it will not provide comments*, Transmission Provider shall tender a draft LGIA, together with draft appendices. The draft LGIA shall be in the form of Transmission Provider's FERC-approved standard form LGIA, which is in Appendix *5*[6]. Interconnection Customer shall execute and return the *LGIA and* completed draft appendices within thirty (30) Calendar Days*, unless (1) the sixty (60) Calendar Day negotiation period under Section 11.2 of this LGIP has commenced, or (2) LGIA execution, or filing unexecuted, has been delayed to await the Affected System Study Report pursuant to Section 11.2.1 of this LGIP*.

11.2 Negotiation.

Notwithstanding Section 11.1, at the request of Interconnection Customer Transmission Provider shall begin negotiations with Interconnection Customer concerning the appendices to the LGIA at any time after Interconnection Customer executes the Interconnection Facilities Study Agreement. Transmission Provider and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. If Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to Section 11.1 and request submission of the unexecuted LGIA with FERC or initiate Dispute Resolution procedures pursuant to Section 13.5. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the

unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if Interconnection Customer has not executed the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to Section 13.5 within sixty (60) Calendar Days of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall provide to Interconnection Customer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

11.2.1 Delay in LGIA Execution, or Filing Unexecuted, to Await Affected System Study Report.

If Interconnection Customer has not received its Affected System Study Report from the Affected System Operator prior to the date that it would be required to execute its LGIA (or request that its LGIA be filed unexecuted) pursuant to Section 11.1 of this LGIP, Transmission Provider shall, upon request of Interconnection Customer, extend this deadline to thirty (30) Calendar Days after Interconnection Customer's receipt of the Affected System Study Report. If Interconnection Customer, after delaying LGIA execution, or requesting unexecuted filing, to await Affected System Study Results, decides to proceed to LGIA execution, or request unexecuted filing, without those results, it may notify Transmission Provider of its intent to proceed with LGIA execution (or request that its LGIA be filed unexecuted) pursuant to Section 11.1 of this LGIP. If Transmission Provider determines that further delay to the LGIA execution date would cause a material impact on the cost or timing of an equal- or lower-queued interconnection customer, Transmission Provider must notify Interconnection Customer of such impacts and set the deadline to execute the LGIA (or request that the LGIA be filed unexecuted) to thirty (30) Calendar Days after such notice is provided.

11.3 Execution and Filing.

Simultaneously with submitting the executed LGIA to Transmission Provider, or within ten (10) Business Days after the Interconnection Customer requests that the Transmission Provider file the LGIA unexecuted at the Commission, [Within fifteen (15) Business Days after receipt of the final executed LGIA,]Interconnection Customer shall provide Transmission Provider *with* [(A) reasonable evidence that continued Site Control or (B) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs]*(1) demonstration of continued Site Control pursuant to Section 8.1(2) of this LGIP; and (2) the LGIA Deposit equal to twenty percent (20%) of Interconnection Customer's estimated Network Upgrade costs identified in the draft LGIA minus the total amount of Commercial Readiness Deposits that Interconnection Customer has provided to Transmission Provider for its Interconnection Request. Transmission Provider shall use LGIA Deposit as (or as a portion of) the Interconnection Customer's security required under LGIA Article 11.5. Interconnection Customer may*

not request to suspend its LGIA under LGIA Article 5.16 until Interconnection Customer has provided (1) and (2) to Transmission Provider. If Interconnection Customer fails to provide (1) and (2) to Transmission Provider within the thirty (30) Calendar Days allowed for returning the executed LGIA and appendices under LGIP Section 11.1, or within ten (10) Business Days after Interconnection Customer requests that Transmission Provider file the LGIA unexecuted at the Commission as allowed in this Section 11.3 of this LGIP, the Interconnection Request will be deemed withdrawn pursuant to Section 3.7 of this LGIP.

At the same time, Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at Interconnection Customer election, has been achieved *(unless such milestone is inapplicable due to the characteristics of the Generating Facility)*: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract *(or comparable evidence)* for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

Interconnection Customer shall either: (i) execute two originals of the tendered LGIA and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, Transmission Provider shall file the LGIA with FERC, together with its explanation of any matters as to which Interconnection Customer and Transmission Provider disagree and support for the costs that Transmission Provider proposes to charge to Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by Transmission Provider for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

11.4 Commencement of Interconnection Activities.

If Interconnection Customer executes the final LGIA, Transmission Provider and Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA, Interconnection Customer and Transmission Provider shall promptly comply with the unexecuted LGIA, subject to modification by FERC.

Section 12. Construction of Transmission Provider's Interconnection Facilities and Network Upgrades

12.1 Schedule.

Transmission Provider and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing.

12.2.1 General.

In general, the In-Service Date of an Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than Interconnection Customer.

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider: (i) any associated expediting costs and (ii) the cost of such Network Upgrades. Transmission Provider will refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Transmission Provider.

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider any associated expediting costs. Interconnection Customer shall be entitled to transmission credits, if any, for any expediting costs paid.

12.2.4 Amended Interconnection [System Impact]*Cluster* Study *Report*.

An Interconnection [System Impact]*Cluster* Study Report will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study *report* will include those transmission and Large Generating Facilities that are expected to be on or before the requested In-Service Date.

Section 13. Miscellaneous

13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the LGIA; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information.

Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1.

13.1.3 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential

Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies.

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to FERC, its Staff, or a State.

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when its is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

13.1.9

Subject to the exception in Section 13.1.8 *of this LGIP*, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a [Control Area]*Balancing Authority Area* operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10

This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11

Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility.

Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this LGIP. Transmission Provider shall remain primarily liable to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this LGIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs

In the event an Interconnection Customer withdraws its Interconnection Request prior to the commencement of the Cluster Study, Interconnection Customer must pay Transmission Provider the actual costs of processing its Interconnection Request. In the event an Interconnection Customer withdraws after the commencement of the Cluster Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. *The costs of any interconnection study conducted on a clustered basis shall be allocated among each Interconnection Customer within the cluster as follows: {Transmission Provider shall include in this section a description of how the cost of any clustered interconnection study will be allocated.}*

Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection [Customer]*Customers* or offset against the cost of any future Interconnection Studies associated with the applicable [Interconnection Request]*Cluster* prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection [Customer]*Customers* shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefor. *If an Interconnection Customer fails to pay such undisputed costs within the time allotted, its Interconnection Request shall be deemed withdrawn from the Cluster Study Process and will be subject to Withdrawal Penalties pursuant to Section 3.7 of this LGIP.* [Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith.]

13.4 Third Parties Conducting Studies.

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Sections 6.3, 7.4 or 8.3 that Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 6.3, 7.4 or 8.3 within the applicable timeframe for such Interconnection Study, then Interconnection Customer may require Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where Transmission Provider determines that doing so will help maintain or accelerate the study process for Interconnection Customer's pending Interconnection Request and not interfere with Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either Interconnection Customer or Transmission Provider at Transmission Provider's discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this LGIP, Article 26 of the LGIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes.

13.5.1 Submission.

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, the LGIP, or their performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

13.5.2 External Arbitration Procedures.

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Section 13, the terms of this Section 13 shall prevail.

13.5.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA and LGIP and shall have no power to modify or change any provision of the LGIA and LGIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may

be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

13.5.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

13.5.5 Non-binding dispute resolution procedures.

If a Party has submitted a Notice of Dispute pursuant to *S*[s]ection 13.5.1, and the Parties are unable to resolve the claim or dispute through unassisted or assisted negotiations within the thirty (30) Calendar Days provided in that section, and the Parties cannot reach mutual agreement to pursue the *S*[s]ection 13.5 arbitration process, a Party may request that Transmission Provider engage in Non-binding Dispute Resolution pursuant to this section by providing written notice to Transmission Provider ("Request for Non-binding Dispute Resolution"). Conversely, either Party may file a Request for Non-binding Dispute Resolution pursuant to this section without first seeking mutual agreement to pursue the *S*[s]ection 13.5 arbitration process. The process in *S*[s]ection 13.5.5 shall serve as an alternative to, and not a replacement of, the section 13.5 arbitration process. Pursuant to this process, a Transmission Provider must within 30 days of receipt of the Request for Non-binding Dispute Resolution appoint a neutral decision-maker that is an independent subcontractor that shall not have any current or past substantial business or financial relationships with either Party. Unless otherwise agreed by the Parties, the decision-maker shall render a decision within sixty (60) Calendar Days of appointment and shall notify the Parties in writing of such decision and reasons therefore. This decision-maker shall be authorized only to interpret and apply the provisions of the LGIP and LGIA and shall have no power to modify or change any provision of the LGIP and LGIA in any manner. The result reached in this process is not binding, but, unless otherwise agreed, the Parties may cite the record and decision in the non-binding dispute resolution process in future dispute resolution processes, including in a *S*[s]ection 13.5 arbitration, or in a Federal Power Act section 206 complaint. Each Party shall be responsible for its own costs incurred during the process and the cost of the decision-maker shall be divided equally among each Party to the dispute

13.6 Local Furnishing Bonds.

13.6.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds.

This provision is applicable only to a Transmission Provider that has financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this LGIA and LGIP, Transmission Provider shall not be required to provide Interconnection Service to Interconnection Customer pursuant to this LGIA and LGIP if the provision of such Transmission Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance Transmission Provider's facilities that would be used in providing such Interconnection Service.

13.6.2 Alternative Procedures for Requesting Interconnection Service.

If Transmission Provider determines that the provision of Interconnection Service requested by Interconnection Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such Interconnection Service, it shall advise the Interconnection Customer within thirty (30) Calendar Days of receipt of the Interconnection Request.

Interconnection Customer thereafter may renew its request for interconnection using the process specified in Article 5.2(ii) of the Transmission Provider's Tariff.

Section [9]*13.7* Engineering & Procurement ('E&P') Agreement.

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Provider shall offer Interconnection Customer, an E&P Agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which

cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its Interconnection Request or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect: (i) to take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

APPENDIX 1 to LGIP
INTERCONNECTION REQUEST FOR A
LARGE GENERATING FACILITY

1. The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility with Transmission Provider's Transmission System pursuant to a Tariff.
2.
2. This Interconnection Request is for (check one):
3. ______ A proposed new Large Generating Facility.
4. ______ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

3. The type of interconnection service requested (check one):
5. _____ Energy Resource Interconnection Service
6. _____ Network Resource Interconnection Service

4. _____ Check here only if Interconnection Customer requesting Network Resource Interconnection Service also seeks to have its Generating Facility studied for Energy Resource Interconnection Service
7.
5. Interconnection Customer provides the following information:

a. Address or location or the proposed new Large Generating Facility site (to the extent known) or, in the case of an existing Generating Facility, the name and specific location of the existing Generating Facility;

b. Maximum summer at ____ degrees C and winter at _____ degrees C megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

c. General description of the equipment configuration;

d. Commercial Operation Date (Day, Month, and Year);

e. Name, address, telephone number, and e-mail address of Interconnection Customer's contact person;

f. Approximate location of the proposed Point of Interconnection (optional);

g. Interconnection Customer Data (set forth in Attachment A);

h. Primary frequency response operating range for electric storage resources;

i. Requested capacity (in MW) of Interconnection Service (if lower than the Generating Facility Capacity)[.]*;*

j. If applicable, (1) the requested operating assumptions (i.e., whether the interconnecting Generating Facility will or will not charge at peak load) to be used by Transmission Provider that reflect the proposed charging behavior of a Generating Facility that includes at least one electric storage resource, and (2) a description of any control technologies (software and/or hardware) that will limit the operation of the Generating Facility to its intended operation.

6. Applicable deposit amount as specified in the LGIP.
8.
7. Evidence of Site Control as specified in the LGIP (check one)
9.
10. ____ Is attached to this Interconnection Request
11. ____ Will be provided at a later date in accordance with this LGIP

8. This Interconnection Request shall be submitted to the representative indicated below:
12. {To be completed by Transmission Provider}
9. Representative of Interconnection Customer to contact:
13. [To be completed by Interconnection Customer]

10. This Interconnection Request is submitted by:
14.
15. Name of Interconnection Customer:
________________________________ By (signature):
____ Name (type or print): ____ Title:
____ Date:

Attachment A to Appendix 1
Interconnection Request

LARGE GENERATING FACILITY DATA

UNIT RATINGS

kVA ______________ °F __________ Voltage ______________
Power Factor _________
Speed (RPM) _________ Connection (e.g. Wye) ______________
Short Circuit Ratio _________ Frequency, Hertz _____________
Stator Amperes at Rated kVA __________ Field Volts ________________
Max Turbine MW _____________°F ______

Primary frequency response operating range for electric storage resources:
Minimum State of Charge:_____________

Maximum State of Charge:_____________

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ______________________ kW sec/kVA
Moment-of-Inertia, WR^2 = ______________________ lb. ft.^{2}

REACTANCE DATA (PER UNIT-RATED KVA)

	DIRECT AXIS		QUADRATURE AXIS	
Synchronous – saturated	X_{dv}	________	X_{qv}	________
Synchronous – unsaturated	X_{di}	________	X_{qi}	________
Transient – saturated	X'_{dv}	________	X'_{qv}	________
Transient – unsaturated	X'_{di}	________	X'_{qi}	________
Subtransient – saturated	X''_{dv}	________	X''_{qv}	________
Subtransient – unsaturated	X''_{di}	________	X''_{qi}	________
Negative Sequence – saturated	$X2_v$	________		
Negative Sequence – unsaturated	$X2_i$	________		
Zero Sequence – saturated	$X0_v$	________		
Zero Sequence – unsaturated	$X0_i$	________		
Leakage Reactance	Xl_m	________		

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'_{do}	________	T'_{qo}	________
Three-Phase Short Circuit Transient	T'_{d3}	________	T'_{q}	________
Line to Line Short Circuit Transient	T'_{d2}	________		
Line to Neutral Short Circuit Transient	T'_{d1}	________		
Short Circuit Subtransient	T''_{d}	________	T''_{q}	________
Open Circuit Subtransient	T''_{do}	________	T''_{qo}	________

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	T_{a3}	________
Line to Line Short Circuit	T_{a2}	________
Line to Neutral Short Circuit	T_{a1}	________

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION
LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R_1	________
Negative	R_2	________
Zero	R_0	________

Rotor Short Time Thermal Capacity I_2^2t = ________
Field Current at Rated kVA, Armature Voltage and PF = ________ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = ________ amps
Three Phase Armature Winding Capacitance = ________ microfarad
Field Winding Resistance = ________ ohms _____ °C
Armature Winding Resistance (Per Phase) = ________ ohms _____ °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity Self-cooled/
Maximum Nameplate
_______________/_________________kVA

Voltage Ratio(Generator Side/System side/Tertiary)
_______________/________________/_______________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
_______________/_______________/________________

Fixed Taps Available ____

Present Tap Setting ____

IMPEDANCE

Positive Z_1 (on self-cooled kVA rating)_______________ % ________ X/R

Zero Z_0 (on self-cooled kVA rating)_______________ % ________ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request:

____

Elevation: ______________ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:

____

List of adjustable setpoints for the protective equipment or software:

____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS

(*) Field Volts: __________________
(*) Field Amperes: _______________
(*) Motoring Power (kW): ________
(*) Neutral Grounding Resistor (If Applicable): _____________
(*) I_2^2t or K (Heating Time Constant): _____________
(*) Rotor Resistance: _____________
(*) Stator Resistance: _____________
(*) Stator Reactance: ______________
(*) Rotor Reactance: ______________
(*) Magnetizing Reactance: ____________
(*) Short Circuit Reactance: ____________
(*) Exciting Current: _________________
(*) Temperature Rise: _________________
(*) Frame Size: ________________
(*) Design Letter: ______________
(*) Reactive Power Required In Vars (No Load): _________
(*) Reactive Power Required In Vars (Full Load): _________
(*) Total Rotating Inertia, H: _________Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

MODELS FOR NON-SYNCHRONOUS GENERATORS

For a non-synchronous Large Generating Facility, Interconnection Customer shall provide (1) a validated user-defined root mean squared (RMS) positive sequence dynamics model; (2) an appropriately parameterized generic library RMS positive sequence dynamics model, including model block diagram of the inverter control and plant control systems, as defined by the selection in Table 1 or a model otherwise approved by the Western Electricity Coordinating Council, that corresponds to Interconnection Customer's Large Generating Facility; and (3) if applicable, a validated electromagnetic transient model if Transmission Provider performs an electromagnetic transient study as part of the interconnection study process. A user-defined model is a set of programming code created by equipment manufacturers or developers that captures the latest features of controllers that are mainly software based and represents the entities' control strategies but does not necessarily correspond to any generic library model. Interconnection Customer must also demonstrate that the model is validated by providing evidence that the equipment behavior is consistent with the model behavior (e.g., an attestation from Interconnection Customer that the model accurately represents the entire Large Generating Facility; attestations from each equipment manufacturer that the user defined model accurately represents the component of the Large Generating Facility; or test data).

Table 1: Acceptable Generic Library RMS Positive Sequence Dynamics Models

GE PSLF	***Siemens PSS/E****	***PowerWorld Simulator***	***Description***
pvd1		*PVD1*	*Distributed PV system model*
der_a	*DERAU1*	*DER_A*	*Distributed energy resource model*
regc_a	*REGCAU1, REGCA1*	*REGC_A*	*Generator/converter model*
regc_b	*REGCBU1*	*REGC_B*	*Generator/converter model*
wt1g	*WT1G1*	*WT1G and WT1G1*	*Wind turbine model for Type-1 wind turbines (conventional directly connected induction generator)*
wt2g	*WT2G1*	*WT2G and WT2G1*	*Generator model for generic Type-2 wind turbines*
wt2e	*WT2E1*	*WT2E and WT2E1*	*Rotor resistance control model for wound-rotor induction wind-turbine generator wt2g*
reec_a	*REECAU1, REECA1*	*REEC_A*	*Renewable energy electrical control model*

GE PSLF	***Siemens PSS/E****	***PowerWorld Simulator***	***Description***
reec_c	*REECCU1*	*REEC_C*	*Electrical control model for battery energy storage system*
reec_d	*REECDU1*	*REEC_D*	*Renewable energy electrical control model*
wt1t	*WT12T1*	*WT1T and WT12T1*	*Wind turbine model for Type-1 wind turbines (conventional directly connected induction generator)*
wt1p_b	*wt1p_b*	*WT12A1U_B*	*Generic wind turbine pitch controller for WTGs of Types 1 and 2*
wt2t	*WT12T1*	*WT2T*	*Wind turbine model for Type-2 wind turbines (directly connected induction generator wind turbines with an external rotor resistance)*
wtgt_a	*WTDTAU1, WTDTA1*	*WTGT_A*	*Wind turbine drive train model*
wtga_a	*WTARAU1, WTARA1*	*WTGA_A*	*Simple aerodynamic model*
wtgp_a	*WTPTAU1, WTPTA1*	*WTGPT_A*	*Wind Turbine Generator Pitch controller*
wtgq_a	*WTTQAU1, WTTQA1*	*WTGTRQ_A*	*Wind Turbine Generator Torque controller*
wtgwgo_a	*WTGWGOAU*	*WTGWGO_A*	*Supplementary control model for Weak Grids*
wtgibffr_a	*WTGIBFFRA*	*WTGIBFFR_A*	*Inertial-base fast frequency response control*
wtgp_b	*WTPTBU1*	*WTGPT_B*	*Wind Turbine Generator Pitch controller*
wtgt_b	*WTDTBU1*	*WTGT_B*	*Drive train model*

GE PSLF	***Siemens PSS/E****	***PowerWorld Simulator***	***Description***
repc_a	*Type 4: REPCAU1 (v33),* *REPCA1 (v34)* *Type 3: REPCTAU1 (v33),* *REPCTA1 (v34)*	*REPC_A*	*Power Plant Controller*
repc_b	*PLNTBU1*	*REPC_B*	*Power Plant Level Controller for controlling several plants/devices* *In regard to Siemens PSS/E*:* *Names of other models for interface with other devices:* *REA3XBU1, REAX4BU1- for interface with Type 3 and 4 renewable machines* *SWSAXBU1- for interface with SVC (modeled as switched shunt in powerflow)* *SYNAXBU1- for interface with synchronous condenser* *FCTAXBU1- for interface with FACTS device*
repc_c	*REPCCU*	*REPC_C*	*Power plant controller*

[APPENDIX 2 to LGIP]
[INTERCONNECTION FEASIBILITY STUDY AGREEMENT]

[THIS AGREEMENT is made and entered into this___ day of__________, 20___ by and between________________________, a ________________________organized and existing under the laws of the State of ________________________ ("Interconnection Customer"), and ________________________, a ________________________ existing under the laws of the State of ________________________ ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."]

[RECITALS]

[WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection customer dated____________; and]

[WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System; and]

[WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility to the Transmission System, and of any Affected Systems;]

[NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:]

[1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP]

[2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of this LGIP in accordance with the Tariff].

[3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.]

[4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.4.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.4.4 of the LGIP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.]

[5.0 The Interconnection Feasibility Study report shall provide the following information:]

- [preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;]

- [preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and]

- [preliminary description and non-bonding estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit and power flow issues.]

[6.0 Interconnection Customer shall provide a deposit of $10,000 for the performance of the Interconnection Feasibility Study.]

[Upon receipt of the Interconnection Feasibility Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study.]

[Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.]

[7.0 Miscellaneous. The Interconnection Feasibility Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature

of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of this LGIP and the LGIA.]

[IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

{Insert name of Transmission Provider or Transmission Owner, if applicable}

By: ______________________________ By: ______________________________

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

{Insert name of *prospective* Interconnection Customer}

By: ______________________________

Title: ______________________________

Date: ______________________________]

**[Attachment A to Appendix 2
Interconnection Feasibility
Study Agreement]**

**[ASSUMPTIONS USED IN CONDUCTING THE
INTERCONNECTION FEASIBILITY STUDY]**

[The *Informational* Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on
____________:

Designation of Point of Interconnection and configuration to be studied.
Designation of alternative Point(s) of Interconnection and configuration.

{Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider}]

APPENDIX *2*[3] to LGIP
[INTERCONNECTION SYSTEM IMPACT]*CLUSTER* STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of ____________, 20___ by and between ______________, a ____________organized and existing under the laws of the State of _______________, ("Interconnection Customer,") and _________________________, a _________________ organized and existing under the laws of the State of _________________ ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated _________________; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

[WHEREAS, Transmission Provider has completed an Interconnection Feasibility Study (the "[Feasibility] Study") and provided the results of said study to Interconnection Customer (This recital to be omitted if Transmission Provider does not require the Interconnection Feasibility Study.); and]

WHEREAS, Interconnection Customer has requested Transmission Provider to perform [an Interconnection System Impact]*a Cluster* Study to assess the impact of interconnecting the Large Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in this LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed [an Interconnection System Impact]*a Cluster* Study consistent with Section 7.0 of this LGIP in accordance with the Tariff.

16.

3.0 The scope of the [Interconnection System Impact]*Cluster* Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

17.
4.0 The [Interconnection System Impact]*Cluster* Study will be based upon the [results of the Interconnection Feasibility Study and] the technical information provided by Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of this LGIP. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the [Interconnection Customer System Impact]*Cluster* Study. [If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein, the time to complete the Interconnection System Impact Study may be extended.]

18.
5.0 The [Interconnection System Impact]*Cluster* Study [report]*Report* shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and

- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 [Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study.]Transmission Provider's good faith estimate for the time of completion of the [Interconnection System Impact]*Cluster* Study is {insert date}.

Upon receipt of the [Interconnection System Impact]*Cluster* Study Report, Transmission Provider shall charge and Interconnection Customer shall pay *its share of* the actual costs of the [Interconnection System Impact]*Cluster* Study*, consistent with Section 13.3 of this LGIP.*

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The [Interconnection System Impact]*Cluster* Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of this LGIP and LGIA.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

{Insert name of Transmission Provider or Transmission Owner, if applicable}

By: ________________________________

Title: _______________________________

Date: _______________________________

{Insert name of Interconnection Customer}

By: ________________________________

Title: _______________________________

Date: _______________________________

Attachment A to Appendix *2*[3]
[Interconnection System Impact]*Cluster* Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE [INTERCONNECTION SYSTEM IMPACT]*CLUSTER* STUDY

The [Interconnection System Impact]*Cluster* Study will be based upon the *technical information provided by Interconnection Customer in the Interconnection Request,* [results of the Interconnection Feasibility Study,] subject to any modifications in accordance with Section 4.4 of th*is*[e] LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.
Designation of alternative Point(s) of Interconnection and configuration.

{Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider}

APPENDIX *3*[4] to LGIP
INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of _______________, 20___ by and between__________________________, a ___________________ organized and existing under the laws of the State of __________________, ("Interconnection Customer,") and _________________________ a __________________existing under the laws of the State of ____________________, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated _______; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection [System Impact]*Cluster* Study (the "[System Impact]*Cluster* Study") and provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the [Interconnection System Impact]*Cluster* Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study [r]*R*eport (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Large Generating Facility to the Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the [Interconnection System Impact]*Cluster* Study.

5.0 Interconnection Customer shall provide a *Commercial Readiness Deposit per Section 8.1 of this LGIP to enter* [deposit of $100,000 for the performance of] the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

[Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.]

6.0 Miscellaneous. The Interconnection Facilit[y]*ies* Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________ By: ______________________________

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

[Insert name of Interconnection Customer]

By: ______________________________

Title: ______________________________

Date: ______________________________

Attachment A to Appendix *3*[4]
Interconnection Facilities
Study Agreement

INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

Transmission Provider shall [use Reasonable Efforts to]complete the study and issue a draft Interconnection Facilities Study [r]*R*eport to Interconnection Customer within the following number of days after [of]receipt of an executed copy of this Interconnection Facilities Study Agreement:

- ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report, or

- one hundred eighty (180) Calendar Days with no more than a +/- 10 percent cost estimate contained in the report.

Attachment B to Appendix *3*[4]
Interconnection Facilities
Study Agreement

DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?
_____Yes _____ No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____No (Please indicate on one line diagram).

What type of control system or PLC will be located at Interconnection Customer's Large Generating Facility?

____

What protocol does the control system or PLC use?

____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to Transmission Provider's transmission line.

____

Tower number observed in the field. (Painted on tower leg)* ______________________

Number of third party easements required for transmission lines*:

____

* To be completed in coordination with Transmission Provider.

Is the Large Generating Facility in the Transmission Provider's service area?

_____Yes _____No Local provider: __________________________________

Please provide proposed schedule dates:

Begin Construction	Date: ____________________
Generator step-up transformer receives back feed power	Date: ____________________
Generation Testing	Date: ____________________
Commercial Operation	Date: ____________________

APPENDIX *4*[5] to LGIP
OPTIONAL INTERCONNECTION STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of _______________, 20___ by and between__________________________, a ___________________ organized and existing under the laws of the State of __________________, ("Interconnection Customer,") and _________________________ a _________________existing under the laws of the State of ____________________, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ________________;

WHEREAS, Interconnection Customer is proposing to establish an interconnection with the Transmission System; and

WHEREAS, Interconnection Customer has submitted to Transmission Provider an Interconnection Request; and

WHEREAS, on or after the date when Interconnection Customer receives the [Interconnection System Impact] *Cluster* Study results, Interconnection Customer has further requested that Transmission Provider prepare an Optional Interconnection Study;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Optional Interconnection Study consistent with Section 10.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or interconnection service based upon the assumptions specified by Interconnection Customer in Attachment A.

6.0 Interconnection Customer shall provide a deposit of $10,000 for the performance of the Optional Interconnection Study. Transmission Provider's good faith estimate for the time of completion of the Optional Interconnection Study is [insert date].

Upon receipt of the Optional Interconnection Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Optional Study.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Optional Interconnection Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________ By: ______________________________

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ________________________________

[Insert name of Interconnection Customer]

By: ______________________________

Title: ______________________________

Date: ______________________________

APPENDIX 5[6] to LGIP
LARGE GENERATOR INTERCONNECTION AGREEMENT
(SEE LGIA)

APPENDIX *6*[7]
INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Appendix *6*[7] sets forth procedures specific to a wind generating plant. All other requirements of this LGIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by *S*[s]ection 3.3 of this LGIP, may provide to the Transmission Provider a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the base case data as provided for in this LGIP.

No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the Transmission Provider to complete the [System Impact]*Cluster* Study.

APPENDIX 7 to LGIP
TRANSITIONAL CLUSTER STUDY AGREEMENT

THIS AGREEMENT *is made and entered into this ____ day of ______________, 20__ by and between ____________________, a ______________ organized and existing under the laws of the State of ___________________ ("Interconnection Customer"), and ____________________, a ____________________________________ organized and existing under the laws of the State of __________ ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."*

RECITALS

WHEREAS, *Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ______________;*

WHEREAS, *Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System; and*

WHEREAS*, Interconnection Customer has requested Transmission Provider to perform a "Transitional Cluster Study," which combines the Cluster Study and Interconnection Facilities Study, in a single cluster study, followed by any needed restudies, to specify and estimate the cost of the equipment, engineering, procurement, and construction work needed to physically and electrically connect the Large Generating Facility to Transmission Provider's Transmission System; and*

WHEREAS*, Interconnection Customer has a valid Queue Position as of the {Transmission Provider to insert effective date of compliance filing}.*

NOW, THEREFORE, *in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:*

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in this LGIP.

2.0 Interconnection Customer elects, and Transmission Provider shall cause to be performed, a Transitional Cluster Study.

3.0 The Transitional Cluster Study shall be based upon the technical information provided by Interconnection Customer in the Interconnection Request. Transmission Provider reserves the right to request additional technical information

from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Transitional Cluster Study and Interconnection Customer shall provide such data as quickly as reasonable.

4.0 Pursuant to Section 5.1.1.2 of this LGIP, the interim Transitional Cluster Study Report shall provide the information below:

- *identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;*

- *identification of any thermal overload or voltage limit violations resulting from the interconnection;*

19.

- *identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and*

- *Transmission Provider's Interconnection Facilities and Network Upgrades that are expected to be required as a result of the Interconnection Request(s) and a non-binding, good faith estimate of cost responsibility and a non-binding, good faith estimated time to construct.*

5.0 Pursuant to Section 5.1.1.2 of this LGIP, the final Transitional Cluster Study Report shall: (1) provide all the information included in the interim Transitional Cluster Study Report; (2) provide a description of, estimated cost of, and schedule for required facilities to interconnect the Generating Facility to the Transmission System; and (3) address the short circuit, instability, and power flow issues identified in the interim Transitional Cluster Study Report.

6.0 Interconnection Customer has met the requirements described in Section 5.1.1.2 of this LGIP.

20.

7.0 Interconnection Customer previously provided a deposit for the performance of Interconnection Studies. Upon receipt of the final Transitional Cluster Study Report, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Transitional Cluster Study. Any difference between the study deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, in accordance with the provisions of Section 13.3 of this LGIP.

8.0 Miscellaneous. The Transitional Cluster Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability

and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of this LGIP and the LGIA.

IN WITNESS WHEREOF, *the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.*

{Insert name of Transmission Provider or Transmission Owner, if applicable}

By: __

Title:

Date: ______

{Insert name of Interconnection Customer}

By: __

Title:

Date: ______

APPENDIX 8 to LGIP
TRANSITIONAL SERIAL INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT *is made and entered into this ____ day of ___, 20__, by and between ____________________, a ______________ organized and existing under the laws of the State of ___________________ ("Interconnection Customer") and __________________, a _____________________________________ organized and existing under the laws of the State of __________ ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."*

RECITALS

WHEREAS, *Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Large Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ______; and*

WHEREAS, *Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System; and*

WHEREAS, *Interconnection Customer has requested Transmission Provider to continue processing its Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement, and construction work needed to implement the conclusions of the final interconnection system impact study (from the previously effective serial study process) in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the Transmission System; and*

WHEREAS*, Transmission Provider has provided an Interconnection Facilities Study Agreement to the Interconnection Customer on or before {Transmission Provider to insert effective date of compliance filing}.*

NOW, THEREFORE, *in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:*

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in this LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection Facilities Study consistent with Section 8 of this LGIP.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A to this Agreement, which shall be the same assumptions as the previous Interconnection Facilities Study Agreement executed by the Interconnection Customer.

4.0 The Interconnection Facilities Study Report shall: (1) provide a description, estimated cost of (consistent with Attachment A), and schedule for required facilities to interconnect the Large Generating Facility to the Transmission System; and (2) address the short circuit, instability, and power flow issues identified in the most recently published Cluster Study Report.

5.0 Interconnection Customer has met the requirements described in Section 5.1.1.1 of this LGIP. The time for completion of the Interconnection Facilities Study is specified in Attachment A, and shall be no later than 150 Calendar Days after {Transmission Provider to insert effective date accepted on compliance}.

6.0 Interconnection Customer previously provided a deposit of __________________ dollars ($___) for the performance of the Interconnection Facilities Study.

7.0 Upon receipt of the Interconnection Facilities Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Facilities Study.

8.0 Any difference between the study deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

9.0 Miscellaneous. The Interconnection Facilities Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of this LGIP and this LGIA.

***IN WITNESS WHEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.*

{Insert name of Transmission Provider or Transmission Owner, if applicable}
By: __

Title:

Date: ______

{Insert name of Interconnection Customer}

By: __

Title:

Date: ______

Attachment A to Appendix 8
Transitional Serial Interconnection Facilities Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE TRANSITIONAL SERIAL INTERCONNECTION FACILITIES STUDY

{Assumptions to be completed by Interconnection Customer and Transmission Provider}

APPENDIX 9 to LGIP
TWO-PARTY AFFECTED SYSTEM STUDY AGREEMENT

THIS AGREEMENT *is made and entered into this ___ day of _______________, 20___, by and between _________________________, a ______________________ organized and existing under the laws of the State of ______________________ (Affected System Interconnection Customer) and ________________, a _________________ organized and existing under the laws of the State of ______________ (Transmission Provider). Affected System Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."*

RECITALS

WHEREAS, *Affected System Interconnection Customer is proposing to develop a {description of generating facility or generating capacity addition to an existing generating facility} consistent with the interconnection request submitted by Affected System Interconnection Customer to {name of host transmission provider}, dated _________________, for which {name of host transmission provider} found impacts on Transmission Provider's Transmission System; and*

WHEREAS, *Affected System Interconnection Customer desires to interconnect the {generating facility} with {name of host transmission provider}'s transmission system;*

NOW, THEREFORE, *in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:*

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in this LGIP.

2.0 Transmission Provider shall coordinate with Affected System Interconnection Customer to perform an Affected System Study consistent with Section 9 of this LGIP.

3.0 The scope of the Affected System Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Affected System Study will be based upon the technical information provided by Affected System Interconnection Customer and {name of host

transmission provider}. Transmission Provider reserves the right to request additional technical information from Affected System Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Affected System Study.

5.0 The Affected System Study shall provide the following information:

- *identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;*

- *identification of any thermal overload or voltage limit violations resulting from the interconnection;*

- *identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;*

- *non-binding, good faith estimated cost and time required to construct facilities required on Transmission Provider's Transmission System to accommodate the interconnection of the {generating facility} to the transmission system of the host transmission provider; and*

- *description of how such facilities will address the identified short circuit, instability, and power flow issues.*

6.0 Affected System Interconnection Customer shall provide a deposit of __________ for performance of the Affected System Study. Upon receipt of the results of the Affected System Study by the Affected System Interconnection Customer, Transmission Provider shall charge, and Affected System Interconnection Customer shall pay, the actual cost of the Affected System Study. Any difference between the deposit and the actual cost of the Affected System Study shall be paid by or refunded to Affected System Interconnection Customer, as appropriate, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations.

7.0 This Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability, and assignment, which reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and

the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP.

IN WITNESS THEREOF, *the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.*

{Insert name of Transmission Provider}

By:	______________________________	*By:*	______________________________
Title:	______________________________	*Title:*	______________________________
Date:	______________________________	*Date:*	______________________________

{Insert name of Affected System Interconnection Customer}

By: ______________________________
Title: ______________________________
Date: ______________________________

Project No. ____

Attachment A to Appendix 9
Two-Party Affected System Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE AFFECTED SYSTEM STUDY

The Affected System Study will be based upon the following assumptions:
{Assumptions to be completed by Affected System Interconnection Customer and Transmission Provider}

APPENDIX 10 to LGIP
MULTIPARTY AFFECTED SYSTEM STUDY AGREEMENT

THIS AGREEMENT *is made and entered into this ___ day of _______________, 20___, by and among _________________________, a _______________________ organized and existing under the laws of the State of _______________________ (Affected System Interconnection Customer); _______________________, a _______________________ organized and existing under the laws of the State of_______________________ (Affected System Interconnection Customer); and _________________, a __________________ organized and existing under the laws of the State of ______________ (Transmission Provider). Affected System Interconnection Customers and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties." When it is not important to differentiate among them, Affected System Interconnection Customers each may be referred to as "Affected System Interconnection Customer" or collectively as the "Affected System Interconnection Customers."*

RECITALS

WHEREAS, *Affected System Interconnection Customers are proposing to develop {description of generating facilities or generating capacity additions to an existing generating facility}, consistent with the interconnection requests submitted by Affected System Interconnection Customers to {name of host transmission provider}, dated __________________, for which {name of host transmission provider} found impacts on Transmission Provider's Transmission System; and*

WHEREAS, *Affected System Interconnection Customers desire to interconnect the {generating facilities} with {name of host transmission provider}'s transmission system;*

NOW, THEREFORE, *in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:*

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in this LGIP.

2.0 Transmission Provider shall coordinate with Affected System Interconnection Customers to perform an Affected System Study consistent with Section 9 of this LGIP.

3.0 The scope of the Affected System Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Affected System Study will be based upon the technical information provided by Affected System Interconnection Customers and {name of host transmission provider}. Transmission Provider reserves the right to request additional technical information from Affected System Interconnection Customers as may reasonably become necessary consistent with Good Utility Practice during the course of the Affected System Study.

5.0 The Affected System Study shall provide the following information:

- *identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;*

- *identification of any thermal overload or voltage limit violations resulting from the interconnection;*

- *identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;*

- *non-binding, good faith estimated cost and time required to construct facilities required on Transmission Provider's Transmission System to accommodate the interconnection of the {generating facilities} to the transmission system of the host transmission provider; and*

- *description of how such facilities will address the identified short circuit, instability, and power flow issues.*

6.0 Affected System Interconnection Customers shall each provide a deposit of __________for performance of the Affected System Study. Upon receipt of the results of the Affected System Study by the Affected System Interconnection Customers, Transmission Provider shall charge, and Affected System Interconnection Customers shall pay, the actual cost of the Affected System Study. Any difference between the deposit and the actual cost of the Affected System Study shall be paid by or refunded to Affected System Interconnection Customers, as appropriate, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations.

7.0 This Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability, and assignment, which reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP.

IN WITNESS THEREOF, *the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.*

{Insert name of Transmission Provider}

By: ______________________________ *By:* ______________________________
Title: ______________________________ *Title:* ______________________________
Date: ______________________________ *Date:* ______________________________

{Insert name of Affected System Interconnection Customer}

By: ______________________________
Title: ______________________________
Date: ______________________________

Project No. ____

{Insert name of Affected System Interconnection Customer}

By: ______________________________
Title: ______________________________
Date: ______________________________

Project No. ____

Attachment A to Appendix 10
Multiparty Affected System Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE MULTIPARTY AFFECTED SYSTEM STUDY

The Affected System Study will be based upon the following assumptions:
{Assumptions to be completed by Affected System Interconnection Customers and Transmission Provider}

APPENDIX 11 TO LGIP
TWO-PARTY AFFECTED SYSTEM FACILITIES CONSTRUCTION AGREEMENT

THIS AGREEMENT *is made and entered into this ____ day of _________, 20__, by and between _______________________________, organized and existing under the laws of the State of _________________ (Affected System Interconnection Customer) and__________________, an entity organized under the laws of the State of ______________ (Transmission Provider). Affected System Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."*

RECITALS

WHEREAS, *Affected System Interconnection Customer is proposing to develop a {description of generating facility or generating capacity addition to an existing generating facility} consistent with the interconnection request submitted by Affected System Interconnection Customer to {name of host transmission provider}, dated _________________, for which {name of host transmission provider} found impacts on Transmission Provider's Transmission System; and*

WHEREAS, *Affected System Interconnection Customer desires to interconnect the {generating facility} to {name of host transmission provider}'s transmission system; and*

WHEREAS, *additions, modifications, and upgrade(s) must be made to certain existing facilities of Transmission Provider's Transmission System to accommodate such interconnection; and*

WHEREAS, *Affected System Interconnection Customer has requested, and Transmission Provider has agreed, to enter into this Agreement for the purpose of facilitating the construction of necessary Affected System Network Upgrade(s);*

NOW, THEREFORE, *in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:*

ARTICLE 1
DEFINITIONS

When used in this Agreement, with initial capitalization, the terms specified and not otherwise defined in this Agreement shall have the meanings indicated in this LGIP.

ARTICLE 2
TERM OF AGREEMENT

2.1 Effective Date. *This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC.*

2.2 Term.

2.2.1 General. *This Agreement shall become effective as provided in Article 2.1 and shall continue in full force and effect until the earlier of (1) the final repayment, where applicable, by Transmission Provider of the amount funded by Affected System Interconnection Customer for Transmission Provider's design, procurement, construction and installation of the Affected System Network Upgrade(s) provided in Appendix A; (2) the Parties agree to mutually terminate this Agreement; (3) earlier termination is permitted or provided for under Appendix A of this Agreement; or (4) Affected System Interconnection Customer terminates this Agreement after providing Transmission Provider with written notice at least sixty (60) Calendar Days prior to the proposed termination date, provided that Affected System Interconnection Customer has no outstanding contractual obligations to Transmission Provider under this Agreement. No termination of this Agreement shall be effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination. The term of this Agreement may be adjusted upon mutual agreement of the Parties if (1) the commercial operation date for the {generating facility} is adjusted in accordance with the rules and procedures established by {name of host transmission provider} or (2) the in-service date for the Affected System Network Upgrade(s) is adjusted in accordance with the rules and procedures established by Transmission Provider.*

2.2.2 Termination Upon Default. *Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 5 of this Agreement where Breach and Breaching Party are defined in Article 5. Defaulting Party shall mean the Party that is in Default. In the event of a Default by a Party, the non-Defaulting Party shall have the termination rights described in Articles 5 and 6; provided, however, Transmission Provider may not terminate this Agreement if Affected System Interconnection Customer is the Defaulting Party and compensates Transmission Provider within thirty (30) Calendar Days for the amount of damages billed to Affected System Interconnection Customer by Transmission Provider for any such damages, including costs and expenses, incurred by Transmission Provider as a result of such Default.*

2.2.3 Consequences of Termination. *In the event of a termination by either Party, other than a termination by Affected System Interconnection Customer due to a Default by Transmission Provider, Affected System Interconnection Customer shall be responsible for the payment to Transmission Provider of all amounts then due and payable for construction and installation of the Affected System Network Upgrade(s) (including, without limitation, any equipment ordered related to such construction), plus all out-of-pocket expenses incurred by Transmission Provider in connection with the*

construction and installation of the Affected System Network Upgrade(s), through the date of termination, and, in the event of the termination of the entire Agreement, any actual costs which Transmission Provider reasonably incurs in (1) winding up work and construction demobilization and (2) ensuring the safety of persons and property and the integrity and safe and reliable operation of Transmission Provider's Transmission System. Transmission Provider shall use Reasonable Efforts to minimize such costs.

2.2.4 Reservation of Rights. *Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Affected System Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.*

2.3 Filing. *Transmission Provider shall file this Agreement (and any amendment hereto) with the appropriate Governmental Authority, if required. Affected System Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 8. If Affected System Interconnection Customer has executed this Agreement, or any amendment thereto, Affected System Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.*

2.4 Survival. *This Agreement shall continue in effect after termination, to the extent necessary, to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Agreement; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this Agreement or other applicable agreements, to disconnect, remove, or salvage its own facilities and equipment.*

2.5 Termination Obligations. *Upon any termination pursuant to this Agreement, Affected System Interconnection Customer shall be responsible for the payment of all costs or other contractual obligations incurred prior to the termination date, including previously incurred capital costs, penalties for early termination, and costs of removal and site restoration.*

ARTICLE 3
CONSTRUCTION OF AFFECTED SYSTEM NETWORK UPGRADE(S)

3.1 Construction.

3.1.1 Transmission Provider Obligations. *Transmission Provider shall (or shall cause such action to) design, procure, construct, and install, and Affected System Interconnection Customer shall pay, consistent with Article 3.2, the costs of all Affected System Network Upgrade(s) identified in Appendix A. All Affected System Network Upgrade(s) designed, procured, constructed, and installed by Transmission Provider pursuant to this Agreement shall satisfy all requirements of applicable safety and/or engineering codes and comply with Good Utility Practice, and further, shall satisfy all Applicable Laws and Regulations. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, or any Applicable Laws and Regulations.*

3.1.2 Suspension of Work.

3.1.2.1 Right to Suspend. *Affected System Interconnection Customer must provide to Transmission Provider written notice of its request for suspension. Only the milestones described in the Appendices of this Agreement are subject to suspension under this Article 3.1.2. Affected System Network Upgrade(s) will be constructed on the schedule described in the Appendices of this Agreement unless: (1) construction is prevented by the order of a Governmental Authority; (2) the Affected System Network Upgrade(s) are not needed by any other Interconnection Customer; or (3) Transmission Provider determines that a Force Majeure event prevents construction. In the event of (1), (2), or (3), any security paid to Transmission Provider under Article 4.1 of this Agreement shall be released by Transmission Provider upon the determination by Transmission Provider that the Affected System Network Upgrade(s) will no longer be constructed. If suspension occurs, Affected System Interconnection Customer shall be responsible for the costs which Transmission Provider incurs (i) in accordance with this Agreement prior to the suspension; (ii) in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of Transmission Provider's Transmission System and, if applicable, any costs incurred in connection with the cancellation of contracts and orders for material which Transmission Provider cannot reasonably avoid;~~,~~ and (iii) reasonably incurs in winding up work and construction demobilization; provided, however, that, prior to canceling any such contracts or orders, Transmission Provider shall obtain Affected System Interconnection Customer's authorization. Affected System Interconnection Customer shall be responsible for all costs incurred in connection with Affected System Interconnection Customer's failure to authorize cancellation of such contracts or orders.*

Interest on amounts paid by Affected System Interconnection Customer to Transmission Provider for the design, procurement, construction, and installation of the Affected System Network Upgrade(s) shall not accrue during periods in which Affected System Interconnection Customer has suspended construction under this Article 3.1.2.

Transmission Provider shall invoice Affected System Interconnection Customer pursuant to Article 4 and will use Reasonable Efforts to minimize its costs. In the event Affected System Interconnection Customer suspends work by Affected System Transmission Provider required under this Agreement pursuant to this Article 3.1.2.1, and has not requested Affected System Transmission Provider to recommence the work required under this Agreement on or before the expiration of three (3) years following commencement of such suspension, this Agreement shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Affected System Transmission Provider, whichever is earlier, if no effective date of suspension is specified.

3.1.2.2 Recommencing of Work. *If Affected System Interconnection Customer requests that Transmission Provider recommence construction of Affected System Network Upgrade(s), Transmission Provider shall have no obligation to afford such work the priority it would have had but for the prior actions of Affected System Interconnection Customer to suspend the work. In such event, Affected System Interconnection Customer shall be responsible for any costs incurred in recommencing the work. All recommenced work shall be completed pursuant to an amended schedule for the interconnection agreed to by the Parties. Transmission Provider has the right to conduct a restudy of the Affected System Study if conditions have materially changed subsequent to the request to suspend. Affected System Interconnection Customer shall be responsible for the costs of any studies or restudies required.*

3.1.2.3 Right to Suspend Due to Default. *Transmission Provider reserves the right, upon written notice to Affected System Interconnection Customer, to suspend, at any time, work by Transmission Provider due to Default by Affected System Interconnection Customer. Affected System Interconnection Customer shall be responsible for any additional expenses incurred by Transmission Provider associated with the construction and installation of the Affected System Network Upgrade(s) (as set forth in Article 2.2.3) upon the occurrence of either a Breach that Affected System Interconnection Customer is unable to cure-pursuant to Article 5 or a Default pursuant to Article 5. Any form of suspension by Transmission Provider shall not be barred by Articles 2.2.2, 2.2.3, or 5.2.2, nor shall it affect Transmission Provider's right to terminate the work or this Agreement pursuant to Article 6.*

3.1.3 Construction Status. *Transmission Provider shall keep Affected System Interconnection Customer advised periodically as to the progress of its design,*

procurement and construction efforts, as described in Appendix A. Affected System Interconnection Customer may, at any time and reasonably, request a progress report from Transmission Provider. If, at any time, Affected System Interconnection Customer determines that the completion of the Affected System Network Upgrade(s) will not be required until after the specified in-service date, Affected System Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of the Affected System Network Upgrade(s) would be required. Transmission Provider may delay the in-service date of the Affected System Network Upgrade(s) accordingly.

3.1.4 Timely Completion. *Transmission Provider shall use Reasonable Efforts to design, procure, construct, install, and test the Affected System Network Upgrade(s) in accordance with the schedule set forth in Appendix A, which schedule may be revised from time to time by mutual agreement of the Parties. If any event occurs that will affect the time or ability to complete the Affected System Network Upgrade(s), Transmission Provider shall promptly notify Affected System Interconnection Customer. In such circumstances, Transmission Provider shall, within fifteen (15) Calendar Days of such notice, convene a meeting with Affected System Interconnection Customer to evaluate the alternatives available to Affected System Interconnection Customer. Transmission Provider shall also make available to Affected System Interconnection Customer all studies and work papers related to the event and corresponding delay, including all information that is in the possession of Transmission Provider that is reasonably needed by Affected System Interconnection Customer to evaluate alternatives, subject to confidentiality arrangements consistent with Article 8. Transmission Provider shall, at Affected System Interconnection Customer's request and expense, use Reasonable Efforts to accelerate its work under this Agreement to meet the schedule set forth in Appendix A, provided that (1) Affected System Interconnection Customer authorizes such actions, such authorization to be withheld, conditioned, or delayed by Affected System Interconnection Customer only if it can demonstrate that the acceleration would have a material adverse effect on it; and (2) the Affected System Interconnection Customer funds costs associated therewith in advance.*

3.2 Interconnection Costs.

3.2.1 Costs. *Affected System Interconnection Customer shall pay to Transmission Provider costs (including taxes and financing costs) associated with seeking and obtaining all necessary approvals and of designing, engineering, constructing, and testing the Affected System Network Upgrade(s), as identified in Appendix A, in accordance with the cost recovery method provided herein. Unless Transmission Provider elects to fund the Affected System Network Upgrade(s), they shall be initially funded by Affected System Interconnection Customer.*

3.2.1.1 Lands of Other Property Owners. *If any part of the Affected System Network Upgrade(s) is to be installed on property owned by persons other than Affected System Interconnection Customer or Transmission Provider, Transmission Provider shall, at Affected System Interconnection Customer's expense, use efforts similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority to the extent permitted and consistent with Applicable Laws and Regulations and, to the extent consistent with such Applicable Laws and Regulations, to procure from such persons any rights of use, licenses, rights-of-way, and easements that are necessary to construct, operate, maintain, test, inspect, replace, or remove the Affected System Network Upgrade(s) upon such property.*

3.2.2 Repayment.

3.2.2.1 Repayment. *Consistent with Articles 11.4.1 and 11.4.2 of the Transmission Provider's pro forma LGIA, Affected System Interconnection Customer shall be entitled to a cash repayment by Transmission Provider of the amount paid to Transmission Provider, if any, for the Affected System Network Upgrade(s), including any tax gross-up or other tax-related payments associated with the Affected System Network Upgrade(s), and not refunded to Affected System Interconnection Customer pursuant to Article 3.3.1 or otherwise. The Parties may mutually agree to a repayment schedule, to be outlined in Appendix A, not to exceed twenty (20) years from the commercial operation date, for the complete repayment for all applicable costs associated with the Affected System Network Upgrade(s). Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR 35.19 a(a)(2)(iii) from the date of any payment for Affected System Network Upgrade(s) through the date on which Affected System Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interest shall not accrue during periods in which Affected System Interconnection Customer has suspended construction pursuant to Article 3.1.2. Affected System Interconnection Customer may assign such repayment rights to any person.*

3.2.2.2 Impact of Failure to Achieve Commercial Operation. *If the Affected System Interconnection Customer's generating facility fails to achieve commercial operation, but it or another generating facility is later constructed and makes use of the Affected System Network Upgrade(s), Transmission Provider shall at that time reimburse Affected System Interconnection Customer for the amounts advanced for the Affected System Network Upgrade(s). Before any such reimbursement can occur, Affected System Interconnection Customer (or the entity that ultimately constructs the generating facility, if different), is responsible for identifying the entity to which the reimbursement must be made.*

3.3 Taxes.

3.3.1 Indemnification for Contributions in Aid of Construction. *With regard only to payments made by Affected System Interconnection Customer to Transmission Provider for the installation of the Affected System Network Upgrade(s), Transmission Provider shall not include a gross-up for income taxes in the amounts it charges Affected System Interconnection Customer for the installation of the Affected System Network Upgrade(s) unless (1) Transmission Provider has determined, in good faith, that the payments or property transfers made by Affected System Interconnection Customer to Transmission Provider should be reported as income subject to taxation, or (2) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation. Affected System Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with this Article, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.*

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten (10)-year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the Internal Revenue Service, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article. Notwithstanding the foregoing provisions of this Article 3.3.1, and to the extent permitted by law, to the extent that the receipt of such payments by Transmission Provider is determined by any Governmental Authority to constitute income by Transmission Provider subject to taxation, Affected System Interconnection Customer shall protect, indemnify, and hold harmless Transmission Provider and its Affiliates, from all claims by any such Governmental Authority for any tax, interest, and/or penalties associated with such determination. Upon receiving written notification of such determination from the Governmental Authority, Transmission Provider shall provide Affected System Interconnection Customer with written notification within thirty (30) Calendar Days of such determination and notification. Transmission Provider, upon the timely written request by Affected System Interconnection Customer and at Affected System Interconnection Customer's expense, shall appeal, protest, seek abatement of, or otherwise oppose such determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the compromise or settlement of the claim; provided that Transmission Provider shall cooperate and consult in good faith with Affected System Interconnection Customer regarding the conduct of such contest. Affected System Interconnection Customer shall not be required to pay Transmission Provider for the tax, interest, and/or penalties prior to the seventh (7th) Calendar Day before the date on which Transmission Provider (1) is required to pay the tax, interest, and/or penalties or other amount in lieu thereof pursuant to a compromise or settlement of the appeal, protest, abatement, or other contest; (2) is required to pay the tax, interest, and/or penalties as the result of a final, non-appealable order by a Governmental Authority; or (3) is required to pay the

tax, interest, and/or penalties as a prerequisite to an appeal, protest, abatement, or other contest. In the event such appeal, protest, abatement, or other contest results in a determination that Transmission Provider is not liable for any portion of any tax, interest, and/or penalties for which Affected System Interconnection Customer has already made payment to Transmission Provider, Transmission Provider shall promptly refund to Affected System Interconnection Customer any payment attributable to the amount determined to be non-taxable, plus any interest (calculated in accordance with 18 CFR 35.19a(a)(2)(iii)) or other payments Transmission Provider receives or which Transmission Provider may be entitled with respect to such payment. Affected System Interconnection Customer shall provide Transmission Provider with credit assurances sufficient to meet Affected System Interconnection Customer's estimated liability for reimbursement of Transmission Provider for taxes, interest, and/or penalties under this Article 3.3.1. Such estimated liability shall be stated in Appendix A.

To the extent that Transmission Provider is a limited liability company and not a corporation, and has elected to be taxed as a partnership, then the following shall apply: Transmission Provider represents, and the Parties acknowledge, that Transmission Provider is a limited liability company and is treated as a partnership for federal income tax purposes. Any payment made by Affected System Interconnection Customer to Transmission Provider for Affected System Network Upgrade(s) is to be treated as an upfront payment. It is anticipated by the Parties that any amounts paid by Affected System Interconnection Customer to Transmission Provider for Affected System Network Upgrade(s) will be reimbursed to Affected System Interconnection Customer in accordance with the terms of this Agreement, provided Affected System Interconnection Customer fulfills its obligations under this Agreement.

3.3.2 Private Letter Ruling. *At Affected System Interconnection Customer's request and expense, Transmission Provider shall file with the Internal Revenue Service a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Affected System Interconnection Customer to Transmission Provider under this Agreement are subject to federal income taxation. Affected System Interconnection Customer will prepare the initial draft of the request for a private letter ruling and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Affected System Interconnection Customer's knowledge. Transmission Provider and Affected System Interconnection Customer shall cooperate in good faith with respect to the submission of such request.*

3.3.3 Other Taxes. *Upon the timely request by Affected System Interconnection Customer, and at Affected System Interconnection Customer's sole expense, Transmission Provider shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Affected System Interconnection Customer may be required to reimburse Transmission Provider under the terms of this Agreement. Affected System*

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Affected System Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Affected System Interconnection Customer to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Affected System Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider. Each Party shall cooperate with the other Party to maintain each Party's tax status. Nothing in this Agreement is intended to adversely affect any Party's tax-exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds, as described in section 142(f) of the Internal Revenue Code.

ARTICLE 4
SECURITY, BILLING, AND PAYMENTS

4.1 Provision of Security. *By the earlier of (1) thirty (30) Calendar Days prior to the due date for Affected System Interconnection Customer's first payment under the payment schedule specified in Appendix A, or (2) the first date specified in Appendix A for the ordering of equipment by Transmission Provider for installing the Affected System Network Upgrade(s), Affected System Interconnection Customer shall provide Transmission Provider, at Affected System Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring, and installing the applicable portion of Affected System Network Upgrade(s) and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.*

The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider and contain terms and conditions that guarantee payment of any amount that may be due from Affected System Interconnection Customer, up to an agreed-to maximum amount. The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date. The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

4.2 Invoice. *Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due, if any, for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each*

other on the same date through netting, in which case all amounts a Party owes to the other Party under this Agreement, including interest payments, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

4.3 Payment. *Invoices shall be rendered to the paying Party at the address specified by the Parties. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by a Party will not constitute a waiver of any rights or claims that Party may have under this Agreement.*

4.4 Final Invoice. *Within six (6) months after completion of the construction of the Affected System Network Upgrade(s), Transmission Provider shall provide an invoice of the final cost of the construction of the Affected System Network Upgrade(s) and shall set forth such costs in sufficient detail to enable Affected System Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund, with interest (calculated in accordance with 18 CFR 35.19a(a)(2)(iii)), to Affected System Interconnection Customer any amount by which the actual payment by Affected System Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.*

4.5 Interest. *Interest on any unpaid amounts shall be calculated in accordance with 18 CFR 35.19a(a)(2)(iii).*

4.6 Payment During Dispute. *In the event of a billing dispute among the Parties, Transmission Provider shall continue to construct the Affected System Network Upgrade(s) under this Agreement as long as Affected System Interconnection Customer: (1) continues to make all payments not in dispute; and (2) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Affected System Interconnection Customer fails to meet these two requirements, then Transmission Provider may provide notice to Affected System Interconnection Customer of a Default pursuant to Article 5. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to another Party shall pay the amount due with interest calculated in accordance with the methodology set forth in 18 CFR 35.19a(a)(2)(iii).*

ARTICLE 5
BREACH, CURE AND DEFAULT

5.1 Events of Breach. *A Breach of this Agreement shall include the:*

(a) Failure to pay any amount when due;

(b) Failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty, or covenant made in this Agreement;

(c) Failure of a Party to provide such access rights, or a Party's attempt to revoke access or terminate such access rights, as provided under this Agreement; or

(d) Failure of a Party to provide information or data to another Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

5.2 Definition. *Breaching Party shall mean the Party that is in Breach.*

5.3 Notice of Breach, Cure, and Default. *Upon the occurrence of an event of Breach, the Party not in Breach, when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party and to any other person representing a Party to this Agreement identified in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach.*

5.3.1 *Upon receiving written notice of the Breach hereunder, the Breaching Party shall have a period to cure such Breach (hereinafter referred to as the "Cure Period") which shall be sixty (60) Calendar Days.*

5.3.2 *In the event the Breaching Party fails to cure within the Cure Period, the Breaching Party will be in Default of this Agreement, and the non--Defaulting Party may terminate this Agreement in accordance with Article 6.2 of this Agreement or take whatever action at law or in equity as may appear necessary or desirable to enforce the performance or observance of any rights, remedies, obligations, agreement, or covenants under this Agreement.*

5.4 Rights in the Event of Default. *Notwithstanding the foregoing, upon the occurrence of a Default, the non-Defaulting Party shall be entitled to exercise all rights and remedies it may have in equity or at law.*

ARTICLE 6
TERMINATION OF AGREEMENT

6.1 Expiration of Term. *Except as otherwise specified in this Article 6, the Parties' obligations under this Agreement shall terminate at the conclusion of the term of this Agreement.*

6.2 Termination. *In addition to the termination provisions set forth in Article 2.2, a Party may terminate this Agreement upon the Default of the other Party in accordance with Article 5.2.2 of this Agreement. Subject to the limitations set forth in Article 6.3, in the event of a Default, the termination of this Agreement by the non-Defaulting Party shall require a filing at FERC of a notice of termination, which filing must be accepted for filing by FERC.*

6.3 Disposition of Facilities Upon Termination of Agreement.

6.3.1 Transmission Provider Obligations. *Upon termination of this Agreement, unless otherwise agreed to by the Parties in writing, Transmission Provider:*

(a) shall, prior to the construction and installation of any portion of the Affected System Network Upgrade(s) and to the extent possible, cancel any pending orders of, or return, such equipment or material for such Affected System Network Upgrade(s);

(b) may keep in place any portion of the Affected System Network Upgrade(s) already constructed and installed; and,

(c) shall perform such work as may be necessary to ensure the safety of persons and property and to preserve the integrity of Transmission Provider's Transmission System (e.g., construction demobilization to return the system to its original state, wind-up work).

6.3.2 Affected System Interconnection Customer Obligations. *Upon billing by Transmission Provider, Affected System Interconnection Customer shall reimburse Transmission Provider for any costs incurred by Transmission Provider in performance of the actions required or permitted by Article 6.3.1 and for the cost of any Affected System Network Upgrade(s) described in Appendix A. Transmission Provider shall use Reasonable Efforts to minimize costs and shall offset the amounts owed by any salvage value of facilities, if applicable. Affected System Interconnection Customer shall pay these costs pursuant to Article 4.3 of this Agreement.*

6.3.3 Pre-construction or Installation. *Upon termination of this Agreement and prior to the construction and installation of any portion of the Affected System Network Upgrade(s), Transmission Provider may, at its option, retain any portion of such Affected System Network Upgrade(s) not cancelled or returned in accordance with Article 6.3.1(a), in which case Transmission Provider shall be responsible for all costs associated with procuring such Affected System Network Upgrade(s). To the extent that Affected System Interconnection Customer has already paid Transmission Provider for any or all of such costs, Transmission Provider shall refund Affected System Interconnection Customer for those payments. If Transmission Provider elects to not*

retain any portion of such facilities, Transmission Provider shall convey and make available to Affected System Interconnection Customer such facilities as soon as practicable after Affected System Interconnection Customer's payment for such facilities.

6.4 Survival of Rights. *Termination or expiration of this Agreement shall not relieve either Party of any of its liabilities and obligations arising hereunder prior to the date termination becomes effective, and each Party may take whatever judicial or administrative actions as appear necessary or desirable to enforce its rights hereunder. The applicable provisions of this Agreement will continue in effect after expiration, or early termination hereof to the extent necessary to provide for (1) final billings, billing adjustments, and other billing procedures set forth in this Agreement; (2) the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and (3) the confidentiality provisions set forth in Article 8.*

ARTICLE 7
SUBCONTRACTORS

7.1 Subcontractors. *Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services, and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.*

7.1.1 Responsibility of Principal. *The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. In accordance with the provisions of this Agreement, each Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon a Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.*

7.1.2 No Third-Party Beneficiary. *Except as may be specifically set forth to the contrary herein, no subcontractor or any other party is intended to be, nor will it be deemed to be, a third-party beneficiary of this Agreement.*

7.1.3 No Limitation by Insurance. *The obligations under this Article 7 will not be limited in any way by any limitation of any insurance policies or coverages, including any subcontractor's insurance.*

ARTICLE 8
CONFIDENTIALITY

8.1 Confidentiality. *Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied to the other Party prior to the execution of this Agreement.*

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential. The Parties shall maintain as confidential any information that is provided and identified by a Party as Critical Energy Infrastructure Information (CEII), as that term is defined in 18 CFR 388.113(c).

Such confidentiality will be maintained in accordance with this Article 8. If requested by the receiving Party, the disclosing Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

8.1.1 Term. *During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 8 or with regard to CEII, each Party shall hold in confidence and shall not disclose to any person Confidential Information. CEII shall be treated in accordance with FERC policies and regulations.*

8.1.2 Scope. *Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a non-Party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (6) is required, in accordance with Article 8.1.6 of this Agreement, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the receiving Party that it no longer is confidential.*

__8.1.3 Release of Confidential Information.__ No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, agents, consultants, or to non-Parties that may be or are considering providing financing to or equity participation with Affected System Interconnection Customer, or to potential purchasers or assignees of Affected System Interconnection Customer, on a need-to-know basis in connection with this Agreement, unless such person has first been advised of the confidentiality provisions of this Article 8 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 8.

__8.1.4 Rights.__ Each Party shall retain all rights, title, and interest in the Confidential Information that it discloses to the receiving Party. The disclosure by a Party to the receiving Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

__8.1.5 Standard of Care.__ Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication, or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its regulatory requirements.

__8.1.6 Order of Disclosure.__ If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the disclosing Party with prompt notice of such request(s) or requirement(s) so that the disclosing Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

__8.1.7 Termination of Agreement.__ Upon termination of this Agreement for any reason, each Party shall, within ten (10) Business Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the requesting Party) or return to the requesting Party any and all written or electronic Confidential Information received from the requesting Party, except that each Party may keep one copy for archival purposes,

provided that the obligation to treat it as Confidential Information in accordance with this Article 8 shall survive such termination.

8.1.8 Remedies. *The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 8. Each Party accordingly agrees that the disclosing Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party Breaches or threatens to Breach its obligations under this Article 8, which equitable relief shall be granted without bond or proof of damages, and the breaching Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 8, but it shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. Neither Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 8.*

8.1.9 Disclosure to FERC, its Staff, or a State Regulatory Body. *Notwithstanding anything in this Article 8 to the contrary, and pursuant to 18 CFR 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from a Party that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this Agreement prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the Agreement when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.*

8.1.10 *Subject to the exception in Article 8.1.9, any information that a disclosing Party claims is competitively sensitive, commercial, or financial information under this Agreement shall not be disclosed by the receiving Party to any person not employed or retained by the receiving Party, except to the extent disclosure is (1) required by law; (2) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (3) otherwise permitted by consent of the disclosing Party, such consent not to be unreasonably withheld; or (4) necessary to fulfill its obligations under this Agreement or as the Transmission Provider or a balancing authority, including disclosing the*

Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the receiving Party in writing of the information that Party claims is confidential. Prior to any disclosures of that Party's Confidential Information under this subparagraph, or if any non-Party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the Party that received the Confidential Information from the disclosing Party agrees to promptly notify the disclosing Party in writing and agrees to assert confidentiality and cooperate with the disclosing Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order, or other reasonable measures.

ARTICLE 9
INFORMATION ACCESS AND AUDIT RIGHTS

9.1 Information Access. *Each Party shall make available to the other Party information necessary to verify the costs incurred by the other Party for which the requesting Party is responsible under this Agreement and carry out obligations and responsibilities under this Agreement, provided that the Parties shall not use such information for purposes other than those set forth in this Article 9.1 and to enforce their rights under this Agreement.*

9.2 Audit Rights. *Subject to the requirements of confidentiality under Article 8 of this Agreement, the accounts and records related to the design, engineering, procurement, and construction of the Affected System Network Upgrade(s) shall be subject to audit during the period of this Agreement and for a period of twenty-four (24) months following Transmission Provider's issuance of a final invoice in accordance with Article 4.4. Affected System Interconnection Customer at its expense shall have the right, during normal business hours, and upon prior reasonable notice to Transmission Provider, to audit such accounts and records. Any audit authorized by this Article 9.2 shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this Agreement.*

ARTICLE 10
NOTICES

10.1 General. *Any notice, demand, or request required or permitted to be given by a Party to the other Party, and any instrument required or permitted to be tendered or delivered by a Party in writing to another Party, may be so given, tendered, or delivered, as the case may be, by depositing the same with the United States Postal Service with postage prepaid, for transmission by certified or registered mail, addressed to the Parties, or personally delivered to the Parties, at the address set out below:*

To Transmission Provider:

To Affected System Interconnection Customer:

10.2 Billings and Payments. *Billings and payments shall be sent to the addresses shown in Article 10.1 unless otherwise agreed to by the Parties.*

10.3 Alternative Forms of Notice. *Any notice or request required or permitted to be given by a Party to the other Party and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out below:*

To Transmission Provider:

To Affected System Interconnection Customer:

10.4 Execution and Filing. *Affected System Interconnection Customer shall either: (i) execute two originals of this tendered Agreement and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC this Agreement in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of this tendered Agreement (if it does not conform with a FERC-approved standard form of this Agreement) or the request to file this Agreement unexecuted, Transmission Provider shall file this Agreement with FERC, together with its explanation of any matters as to which Affected System Interconnection Customer and Transmission Provider disagree and support for the costs that Transmission Provider proposes to charge to Affected System Interconnection Customer under this Agreement. An unexecuted version of this Agreement should contain terms and conditions deemed appropriate by Transmission Provider for the Affected System Interconnection Customer's generating facility. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted version of this Agreement, they may proceed pending FERC action.*

ARTICLE 11
MISCELLANEOUS

11.1 *This Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, which reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of this LGIP.*

[Signature Page to Follow]

IN WITNESS WHEREOF, *the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original Agreement among the Parties.*

Transmission Provider
{Transmission Provider}
By: ________________________________
Name: ________________________________
Title: ________________________________

Affected System Interconnection Customer
{Affected System Interconnection Customer}
By: ________________________________
Name: ________________________________
Title: ________________________________

Project No. ____

Attachment A to Appendix 11
Two-Party Affected System Facilities Construction Agreement

AFFECTED SYSTEM NETWORK UPGRADE(S), COST ESTIMATES AND RESPONSIBILITY, CONSTRUCTION SCHEDULE AND MONTHLY PAYMENT SCHEDULE

This Appendix A is a part of the Affected System Facilities Construction Agreement between Affected System Interconnection Customer and Transmission Provider.

1.1 Affected System Network Upgrade(s) to be installed by Transmission Provider.

{description}

1.2 First Equipment Order (including permitting).

{description}

1.2.1. Permitting and Land Rights – Transmission Provider Affected System Network Upgrade(s)

{description}

1.3 Construction Schedule. *Where applicable, construction of the Affected System Network Upgrade(s) is scheduled as follows and will be periodically updated as necessary:*

Table 1: Transmission Provider Construction Activities

MILESTONE NUMBER	DESCRIPTION	START DATE	END DATE

Note: Construction schedule assumes that Transmission Provider has obtained final authorizations and security from Affected System Interconnection Customer and all

necessary permits from Governmental Authorities as necessary prerequisites to commence construction of any of the Affected System Network Upgrade(s).

1.4 Payment Schedule.

1.4.1 Timing of and Adjustments to Affected System Interconnection Customer's Payments and Security.

{description}

1.4.2 Monthly Payment Schedule. *Affected System Interconnection Customer's payment schedule is as follows.*

{description}

Table 2: Affected System Interconnection Customer's Payment/Security Obligations for Affected System Network Upgrade(s).

MILESTONE NUMBER	***DESCRIPTION***	***DATE***

Note: Affected System Interconnection Customer's payment or provision of security as provided in this Agreement operates as a condition precedent to Transmission Provider's obligations to construct any Affected System Network Upgrade(s), and failure to meet this schedule will constitute a Breach pursuant to Article 5.1 of this Agreement.

1.5 Permits, Licenses, and Authorizations.

{description}

Attachment B to Appendix 11
Two-Party Affected System Facilities Construction Agreement

NOTIFICATION OF COMPLETED CONSTRUCTION

This Appendix B is a part of the Affected ~~Systems~~ System Facilities Construction Agreement between Affected System Interconnection Customer and Transmission Provider. Where applicable, when Transmission Provider has completed construction of the Affected System Network Upgrade(s), Transmission Provider shall send notice to Affected System Interconnection Customer in substantially the form following:

{Date}

{Affected System Interconnection Customer Address}

Re: Completion of Affected System Network Upgrade(s)

Dear {Name or Title}:

This letter is sent pursuant to the Affected System Facilities Construction Agreement between {Transmission Provider} and {Affected System Interconnection Customer}, dated ____________, 20___.

On {Date}, Transmission Provider completed to its satisfaction all work on the Affected System Network Upgrade(s) required to facilitate the safe and reliable interconnection and operation of Affected System Interconnection Customer's {description of generating facility}. Transmission Provider confirms that the Affected System Network Upgrade(s) are in place.

Thank you.

{Signature}
{Transmission Provider Representative}

Attachment C to Appendix 11
Two-Party Affected System Facilities Construction Agreement

EXHIBITS

This Appendix C is a part of the Affected System Facilities Construction Agreement among Affected System Interconnection Customer and Transmission Provider.

Exhibit A1
Transmission Provider Site Map

Exhibit A2
Site Plan

Exhibit A3
Affected System Network Upgrade(s) Plan & Profile

Exhibit A4
Estimated Cost of Affected System Network Upgrade(s)

	Location	***Facilities to Be Constructed by Transmission Provider***	***Estimate in Dollars***
		Total:	

APPENDIX 12 TO LGIP
MULTIPARTY AFFECTED SYSTEM FACILITIES CONSTRUCTION AGREEMENT

***THIS AGREEMENT** is made and entered into this ____ day of _________, 20__, by and among ______________________________, organized and existing under the laws of the State of _________________ (Affected System Interconnection Customer); _____________________, a _____________________ organized and existing under the laws of the State of _________________ (Affected System Interconnection Customer); and_________________, an entity organized under the laws of the State of _____________ (Transmission Provider). Affected System Interconnection Customers and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties." When it is not important to differentiate among them, Affected System Interconnection Customers each may be referred to as "Affected System Interconnection Customer" or collectively as "Affected System Interconnection Customers."*

RECITALS

***WHEREAS,** Affected System Interconnection Customers are proposing to develop {description of generating facilities or generating capacity additions to an existing generating facility}, consistent with the interconnection requests submitted by Affected System Interconnection Customers to {name of host transmission provider}, dated _________________, for which {name of host transmission provider} found impacts on Transmission Provider's Transmission System; and*

***WHEREAS,** Affected System Interconnection Customers desire to interconnect the {generating facilities} to {name of host transmission provider}'s transmission system; and*

***WHEREAS,** additions, modifications, and upgrade(s) must be made to certain existing facilities of Transmission Provider's Transmission System to accommodate such interconnection; and*

***WHEREAS,** Affected System Interconnection Customers have requested, and Transmission Provider has agreed, to enter into this Agreement for the purpose of facilitating the construction of necessary Affected System Network Upgrade(s);*

***NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:*

ARTICLE 1
DEFINITIONS

When used in this Agreement, with initial capitalization, the terms specified and not otherwise defined in this Agreement shall have the meanings indicated in this LGIP.

ARTICLE 2
TERM OF AGREEMENT

2.1 Effective Date. *This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC.*

2.2 Term.

2.2.1 General. *This Agreement shall become effective as provided in Article 2.1 and shall continue in full force and effect until the earlier of (1) the final repayment, where applicable, by Transmission Provider of the amount funded by Affected System Interconnection Customers for Transmission Provider's design, procurement, construction, and installation of the Affected System Network Upgrade(s) provided in Appendix A; (2) the Parties agree to mutually terminate this Agreement; (3) earlier termination is permitted or provided for under Appendix A of this Agreement; or (4) Affected System Interconnection Customers terminate this Agreement after providing Transmission Provider with written notice at least sixty (60) Calendar Days prior to the proposed termination date, provided that Affected System Interconnection Customers have no outstanding contractual obligations to Transmission Provider under this Agreement. No termination of this Agreement shall be effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination. The term of this Agreement may be adjusted upon mutual agreement of the Parties if the commercial operation date(s) for the {generating facilities} is adjusted in accordance with the rules and procedures established by {name of host transmission provider} or the in-service date for the Affected System Network Upgrade(s) is adjusted in accordance with the rules and procedures established by Transmission Provider.*

2.2.2 Termination Upon Default. *Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 5 of this Agreement where Breach and Breaching Party are defined in Article 5. Defaulting Party shall mean the Party that is in Default. In the event of a Default by a Party, each non-Defaulting Party shall have the termination rights described in Articles 5 and 6; provided, however, Transmission Provider may not terminate this Agreement if an Affected System Interconnection Customer is the Defaulting Party and compensates Transmission Provider within thirty (30) Calendar Days for the amount of damages billed to Affected System Interconnection Customer(s) by Transmission Provider for any such damages, including costs and*

expenses incurred by Transmission Provider as a result of such Default. Notwithstanding the foregoing, Default by one or more Affected System Interconnection Customers shall not provide the other Affected System Interconnection Customer(s), either individually or in concert, with the right to terminate the entire Agreement. The non-Defaulting Party/Parties may, individually or in concert, initiate the removal of an Affected System Interconnection Customer that is a Defaulting Party from this Agreement. Transmission Provider shall not terminate this Agreement or the participation of any Affected System Interconnection Customer without provision being made for Transmission Provider to be fully reimbursed for all of its costs incurred under this Agreement.

2.2.3 Consequences of Termination. *In the event of a termination by a Party, other than a termination by Affected System Interconnection Customer(s) due to a Default by Transmission Provider, each Affected System Interconnection Customer whose participation in this Agreement is terminated shall be responsible for the payment to Transmission Provider of all amounts then due and payable for construction and installation of the Affected System Network Upgrade(s) (including, without limitation, any equipment ordered related to such construction), plus all out-of-pocket expenses incurred by Transmission Provider in connection with the construction and installation of the Affected System Network Upgrade(s), through the date of termination, and, in the event of the termination of the entire Agreement, any actual costs which Transmission Provider reasonably incurs in (1) winding up work and construction demobilization and (2) ensuring the safety of persons and property and the integrity and safe and reliable operation of Transmission Provider's Transmission System. Transmission Provider shall use Reasonable Efforts to minimize such costs. The cost responsibility of other Affected System Interconnection Customers shall be adjusted, as necessary, based on the payments by an Affected System Interconnection Customer that is terminated from the Agreement.*

2.2.4 Reservation of Rights. *Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Affected System Interconnection Customers shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.*

2.3 ***Filing.*** *Transmission Provider shall file this Agreement (and any amendment hereto) with the appropriate Governmental Authority, if required. Affected System Interconnection Customers may request that any information so provided be subject to the confidentiality provisions of Article 8. Each Affected System Interconnection Customer that has executed this Agreement, or any amendment thereto, shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.*

2.4 ***Survival.*** *This Agreement shall continue in effect after termination, to the extent necessary, to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Agreement; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this Agreement or other applicable agreements, to disconnect, remove, or salvage its own facilities and equipment.*

2.5 ***Termination Obligations.*** *Upon any termination pursuant to this Agreement or termination of the participation in this Agreement of an Affected System Interconnection Customer, each Affected System Interconnection Customer shall be responsible for the payment of its proportionate share of all costs or other contractual obligations incurred prior to the termination date, including previously incurred capital costs, penalties for early termination, and costs of removal and site restoration. The cost responsibility of the other Affected System Interconnection Customers shall be adjusted as necessary.*

ARTICLE 3
CONSTRUCTION OF AFFECTED SYSTEM NETWORK UPGRADE(S)

3.1 Construction.

3.1.1 Transmission Provider Obligations. *Transmission Provider shall (or shall cause such action to) design, procure, construct, and install, and Affected System Interconnection Customers shall pay, consistent with Article 3.2, the costs of all Affected System Network Upgrade(s) identified in Appendix A. All Affected System Network Upgrade(s) designed, procured, constructed, and installed by Transmission Provider pursuant to this Agreement shall satisfy all requirements of applicable safety and/or engineering codes and comply with Good Utility Practice, and further, shall satisfy all Applicable Laws and Regulations. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, or any Applicable Laws and Regulations.*

3.1.2 Suspension of Work.

3.1.2.1 Right to Suspend. *Affected System Interconnection Customers must jointly provide to Transmission Provider written notice of their request for suspension. Only the milestones described in the Appendices of this Agreement are subject to suspension under this Article 3.1.2. Affected System Network Upgrade(s) will be constructed on the schedule described in the Appendices of this Agreement unless: (1) construction is prevented by the order of a Governmental Authority; (2) the Affected System Network Upgrade(s) are not needed by any other Interconnection Customer; or (3) Transmission Provider determines that a Force Majeure event prevents construction. In the event of (1), (2), or (3), any security paid to Transmission Provider under Article 4.1 of this Agreement shall be released by Transmission Provider upon the determination by Transmission Provider that the Affected System Network Upgrade(s) will no longer be constructed. If suspension occurs, Affected System Interconnection Customers shall be responsible for the costs which Transmission Provider incurs (i) in accordance with this Agreement prior to the suspension; (ii) in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of Transmission Provider's Transmission System and, if applicable, any costs incurred in connection with the cancellation of contracts and orders for material which Transmission Provider cannot reasonably avoid; and (iii) reasonably incurs in winding up work and construction demobilization; provided, however, that, prior to canceling any such contracts or orders, Transmission Provider shall obtain Affected System Interconnection Customers' authorization. Affected System Interconnection Customers shall be responsible for all costs incurred in connection with Affected System Interconnection Customers' failure to authorize cancellation of such contracts or orders.*

Interest on amounts paid by Affected System Interconnection Customers to Transmission Provider for the design, procurement, construction, and installation of the Affected System Network Upgrade(s) shall not accrue during periods in which Affected System Interconnection Customers have suspended construction under this Article 3.1.2.

Transmission Provider shall invoice Affected System Interconnection Customers pursuant to Article 4 and will use Reasonable Efforts to minimize its costs. In the event Affected System Interconnection Customers suspend work by Affected System Transmission Provider required under this Agreement pursuant to this Article 3.1.2.1, and have not requested Affected System Transmission Provider to recommence the work required under this Agreement on or before the expiration of three (3) years following commencement of such suspension, this Agreement shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Affected System Transmission Provider, whichever is earlier, if no effective date of suspension is specified.

3.1.2.2 Recommencing of Work. *If Affected System Interconnection Customers request that Transmission Provider recommence construction of Affected System Network Upgrade(s), Transmission Provider shall have no obligation to afford such work the priority it would have had but for the prior actions of Affected System Interconnection Customers to suspend the work. In such event, Affected System Interconnection Customers shall be responsible for any costs incurred in recommencing the work. All recommenced work shall be completed pursuant to an amended schedule for the interconnection agreed to by the Parties. Transmission Provider has the right to conduct a restudy of the Affected System Study if conditions have materially changed subsequent to the request to suspend. Affected System Interconnection Customers shall be responsible for the costs of any studies or restudies required.*

3.1.2.3 Right to Suspend Due to Default. *Transmission Provider reserves the right, upon written notice to Affected System Interconnection Customers, to suspend, at any time, work by Transmission Provider due to a Default by Affected System Interconnection Customer(s). Defaulting-Affected System Interconnection Customer(s) shall be responsible for any additional expenses incurred by Transmission Provider associated with the construction and installation of the Affected System Network Upgrade(s) (as set forth in Article 2.2.3) upon the occurrence of a Default pursuant to Article 5. Any form of suspension by Transmission Provider shall not be barred by Articles 2.2.2, 2.2.3, or 5.2.2, nor shall it affect Transmission Provider's right to terminate the work or this Agreement pursuant to Article 6.*

3.1.3 Construction Status. *Transmission Provider shall keep Affected System Interconnection Customers advised periodically as to the progress of its design, procurement, and construction efforts, as described in Appendix A. An Affected System Interconnection Customer may, at any time and reasonably, request a progress report from Transmission Provider. If, at any time, an Affected System Interconnection Customer determines that the completion of the Affected System Network Upgrade(s) will not be required until after the specified in-service date, such Affected System Interconnection Customer will provide written notice to all other Parties of such later date for which the completion of the Affected System Network Upgrade(s) would be required. Transmission Provider may delay the in-service date of the Affected System Network Upgrade(s) accordingly, but only if agreed to by all other Affected System Interconnection Customers.*

3.1.4 Timely Completion. *Transmission Provider shall use Reasonable Efforts to design, procure, construct, install, and test the Affected System Network Upgrade(s) in accordance with the schedule set forth in Appendix A, which schedule may be revised from time to time by mutual agreement of the Parties. If any event occurs that will affect the time or ability to complete the Affected System Network Upgrade(s), Transmission Provider shall promptly notify all other Parties. In such circumstances, Transmission Provider shall, within fifteen (15) Calendar Days of such notice, convene a meeting with*

Affected System Interconnection Customers to evaluate the alternatives available to Affected System Interconnection Customers. Transmission Provider shall also make available to Affected System Interconnection Customers all studies and work papers related to the event and corresponding delay, including all information that is in the possession of Transmission Provider that is reasonably needed by Affected System Interconnection Customers to evaluate alternatives, subject to confidentiality arrangements consistent with Article 8. Transmission Provider shall, at any Affected System Interconnection Customer's request and expense, use Reasonable Efforts to accelerate its work under this Agreement to meet the schedule set forth in Appendix A, provided that (1) Affected System Interconnection Customers jointly authorize such actions, such authorizations to be withheld, conditioned, or delayed by a given Affected System Interconnection Customer only if it can demonstrate that the acceleration would have a material adverse effect on it; and (2) the requesting Affected System Interconnection Customer(s) funds the costs associated therewith in advance, or all Affected System Interconnection Customers agree in advance to fund such costs based on such other allocation method as they may adopt.

3.2 Interconnection Costs.

3.2.1 Costs. *Affected System Interconnection Customers shall pay to Transmission Provider costs (including taxes and financing costs) associated with seeking and obtaining all necessary approvals and of designing, engineering, constructing, and testing the Affected System Network Upgrade(s), as identified in Appendix A, in accordance with the cost recovery method provided herein. Except as expressly otherwise agreed, Affected System Interconnection Customers shall be collectively responsible for these costs, based on their proportionate share of cost responsibility, as provided in Appendix A. Unless Transmission Provider elects to fund the Affected System Network Upgrade(s), they shall be initially funded by the applicable Affected System Interconnection Customer.*

3.2.1.1 Lands of Other Property Owners. *If any part of the Affected System Network Upgrade(s) is to be installed on property owned by persons other than Affected System Interconnection Customers or Transmission Provider, Transmission Provider shall, at Affected System Interconnection Customers' expense, use efforts similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority to the extent permitted and consistent with Applicable Laws and Regulations and, to the extent consistent with such Applicable Laws and Regulations, to procure from such persons any rights of use, licenses, rights-of-way, and easements that are necessary to construct, operate, maintain, test, inspect, replace, or remove the Affected System Network Upgrade(s) upon such property.*

3.2.2 Repayment.

3.2.2.1 Repayment. *Consistent with articles 11.4.1 and 11.4.2 of the Transmission Provider's pro forma LGIA, each Affected System Interconnection Customer shall be entitled to a cash repayment by Transmission Provider of the amount each Affected System Interconnection Customer paid to Transmission Provider, if any, for the Affected System Network Upgrade(s), including any tax gross-up or other tax-related payments associated with the Affected System Network Upgrade(s), and not refunded to Affected System Interconnection Customer pursuant to Article 3.3.1 or otherwise. The Parties may mutually agree to a repayment schedule, to be outlined in Appendix A, not to exceed twenty (20) years from the commercial operation date, for the complete repayment for all applicable costs associated with the Affected System Network Upgrade(s). Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR 35.19 a(a)(2)(iii) from the date of any payment for Affected System Network Upgrade(s) through the date on which Affected System Interconnection Customers receive a repayment of such payment pursuant to this subparagraph. Interest shall not accrue during periods in which Affected System Interconnection Customers have suspended construction pursuant to Article 3.1.2.1. Affected System Interconnection Customers may assign such repayment rights to any person.*

3.2.2.2 Impact of Failure to Achieve Commercial Operation. *If an Affected System Interconnection Customer's generating facility fails to achieve commercial operation, but it or another generating facility is later constructed and makes use of the Affected System Network Upgrade(s), Transmission Provider shall at that time reimburse such Affected System Interconnection Customers for the portion of the Affected System Network Upgrade(s) it funded. Before any such reimbursement can occur, Affected System Interconnection Customer (or the entity that ultimately constructs the generating facility, if different), is responsible for identifying the entity to which the reimbursement must be made.*

3.3 Taxes.

3.3.1 Indemnification for Contributions in Aid of Construction. *With regard only to payments made by Affected System Interconnection Customers to Transmission Provider for the installation of the Affected System Network Upgrade(s), Transmission Provider shall not include a gross-up for income taxes in the amounts it charges Affected System Interconnection Customers for the installation of the Affected System Network Upgrade(s) unless (1) Transmission Provider has determined, in good faith, that the payments or property transfers made by Affected System Interconnection Customers to Transmission Provider should be reported as income subject to taxation, or (2) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation. Affected System Interconnection Customers shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with this Article, within thirty (30) Calendar Days of receiving written notification from*

Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten (10)-year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the Internal Revenue Service, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article. Notwithstanding the foregoing provisions of this Article 3.3.1, and to the extent permitted by law, to the extent that the receipt of such payments by Transmission Provider is determined by any Governmental Authority to constitute income by Transmission Provider subject to taxation, Affected System Interconnection Customers shall protect, indemnify, and hold harmless Transmission Provider and its Affiliates, from all claims by any such Governmental Authority for any tax, interest, and/or penalties associated with such determination. Upon receiving written notification of such determination from the Governmental Authority, Transmission Provider shall provide Affected System Interconnection Customers with written notification within thirty (30) Calendar Days of such determination and notification. Transmission Provider, upon the timely written request by any one or more Affected System Interconnection Customer(s) and at the expense of such Affected System Interconnection Customer(s), shall appeal, protest, seek abatement of, or otherwise oppose such determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the compromise or settlement of the claim; provided that Transmission Provider shall cooperate and consult in good faith with the requesting Affected System Interconnection Customer(s) regarding the conduct of such contest. Affected System Interconnection Customer(s) shall not be required to pay Transmission Provider for the tax, interest, and/or penalties prior to the seventh (7th) Calendar Day before the date on which Transmission Provider (1) is required to pay the tax, interest, and/or penalties or other amount in lieu thereof pursuant to a compromise or settlement of the appeal, protest, abatement, or other contest; (2) is required to pay the tax, interest, and/or penalties as the result of a final, non-appealable order by a Governmental Authority; or (3) is required to pay the tax, interest, and/or penalties as a prerequisite to an appeal, protest, abatement, or other contest. In the event such appeal, protest, abatement, or other contest results in a determination that Transmission Provider is not liable for any portion of any tax, interest, and/or penalties for which any Affected System Interconnection Customer(s) has already made payment to Transmission Provider, Transmission Provider shall promptly refund to such Affected System Interconnection Customer(s) any payment attributable to the amount determined to be non-taxable, plus any interest (calculated in accordance with 18 CFR 35.19a(a)(2)(iii)) or other payments Transmission Provider receives or to which Transmission Provider may be entitled with respect to such payment. Each Affected System Interconnection Customer shall provide Transmission Provider with credit assurances sufficient to meet each Affected System Interconnection Customer's estimated

liability for reimbursement of Transmission Provider for taxes, interest, and/or penalties under this Article 3.3.1. Such estimated liability shall be stated in Appendix A.

To the extent that Transmission Provider is a limited liability company and not a corporation, and has elected to be taxed as a partnership, then the following shall apply: Transmission Provider represents, and the Parties acknowledge, that Transmission Provider is a limited liability company and is treated as a partnership for federal income tax purposes. Any payment made by Affected System Interconnection Customers to Transmission Provider for Affected System Network Upgrade(s) is to be treated as an upfront payment. It is anticipated by the Parties that any amounts paid by each Affected System Interconnection Customer to Transmission Provider for Affected System Network Upgrade(s) will be reimbursed to such Affected System Interconnection Customer in accordance with the terms of this Agreement, provided such Affected System Interconnection Customer fulfills its obligations under this Agreement.

3.3.2 Private Letter Ruling. *At the request and expense of any Affected System Interconnection Customer(s), Transmission Provider shall file with the Internal Revenue Service a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by such Affected System Interconnection Customer(s) to Transmission Provider under this Agreement are subject to federal income taxation. Each Affected System Interconnection Customer desiring such a request will prepare the initial draft of the request for a private letter ruling and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of such Affected System Interconnection Customer's knowledge. Transmission Provider and such Affected System Interconnection Customer(s) shall cooperate in good faith with respect to the submission of such request.*

3.3.3 Other Taxes. *Upon the timely request by any one or more Affected System Interconnection Customer(s), and at such Affected System Interconnection Customer(s)' sole expense, Transmission Provider shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which such Affected System Interconnection Customer(s) may be required to reimburse Transmission Provider under the terms of this Agreement. Affected System Interconnection Customer(s) who requested the action shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. The requesting Affected System Interconnection Customer(s) and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Affected System Interconnection Customer(s) to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable*

after appeal, Affected System Interconnection Customer(s) will be responsible for all taxes, interest, and penalties, other than penalties attributable to any delay caused by Transmission Provider. Each Party shall cooperate with the other Party to maintain each Party's tax status. Nothing in this Agreement is intended to adversely affect any Party's tax-exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds, as described in section 142(f) of the Internal Revenue Code.

ARTICLE 4
SECURITY, BILLING, AND PAYMENTS

4.1 Provision of Security. *By the earlier of (1) thirty (30) Calendar Days prior to the due date for each Affected System Interconnection Customer's first payment under the payment schedule specified in Appendix A, or (2) the first date specified in Appendix A for the ordering of equipment by Transmission Provider for installing the Affected System Network Upgrade(s), each Affected System Interconnection Customer shall provide Transmission Provider, at each Affected System Interconnection Customer's option, a guarantee, a surety bond, letter of credit, or other form of security that is reasonably acceptable to Transmission Provider. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring, and installing the applicable portion of Affected System Network Upgrade(s) and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.*

The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider and contain terms and conditions that guarantee payment of any amount that may be due from such Affected System Interconnection Customer, up to an agreed-to maximum amount. The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date. The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

4.2 Invoice. *Each Party shall submit to the other Parties, on a monthly basis, invoices of amounts due, if any, for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to another Party under this Agreement, including interest payments, shall be netted so that only the net amount remaining due shall be paid by the owing Party.*

4.3 Payment. *Invoices shall be rendered to the paying Party at the address specified by the Parties. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated*

by the invoicing Party. Payment of invoices by a Party will not constitute a waiver of any rights or claims that Party may have under this Agreement.

4.4 Final Invoice. *Within six (6) months after completion of the construction of the Affected System Network Upgrade(s) Transmission Provider shall provide an invoice of the final cost of the construction of the Affected System Network Upgrade(s) and shall set forth such costs in sufficient detail to enable each Affected System Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund, with interest (calculated in accordance with 18 CFR 35.19a(a)(2)(iii)), to each Affected System Interconnection Customer any amount by which the actual payment by Affected System Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.*

4.5 Interest. *Interest on any unpaid amounts shall be calculated in accordance with 18 CFR 35.19a(a)(2)(iii).*

4.6 Payment During Dispute. *In the event of a billing dispute among the Parties, Transmission Provider shall continue to construct the Affected System Network Upgrade(s) under this Agreement as long as each Affected System Interconnection Customer: (1) continues to make all payments not in dispute; and (2) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If any Affected System Interconnection Customer fails to meet these two requirements, then Transmission Provider may provide notice to such Affected System Interconnection Customer of a Default pursuant to Article 5. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to another Party shall pay the amount due with interest calculated in accordance with the methodology set forth in 18 CFR 35.19a(a)(2)(iii).*

ARTICLE 5
BREACH, CURE, AND DEFAULT

5.1 Events of Breach. *A Breach of this Agreement shall include the:*

(a) Failure to pay any amount when due;

(b) Failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty, or covenant made in this Agreement;

(c) Failure of a Party to provide such access rights, or a Party's attempt to revoke access or terminate such access rights, as provided under this Agreement; or

(d) Failure of a Party to provide information or data to another Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

5.2 Definition. *Breaching Party shall mean the Party that is in Breach.*

5.3 Notice of Breach, Cure, and Default. *Upon the occurrence of an event of Breach, any Party aggrieved by the Breach, when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party and to any other person representing a Party to this Agreement identified in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach.*

5.2.1 *Upon receiving written notice of the Breach hereunder, the Breaching Party shall have a period to cure such Breach (hereinafter referred to as the "Cure Period") which shall be sixty (60) Calendar Days. If an Affected System Interconnection Customer is the Breaching Party and the Breach results from a failure to provide payments or security under Article 4.1 of this Agreement, the other Affected System Interconnection Customers, either individually or in concert, may cure the Breach by paying the amounts owed or by providing adequate security, without waiver of contribution rights against the breaching Affected System Interconnection Customer. Such cure for the Breach of an Affected System Interconnection Customer is subject to the reasonable consent of Transmission Provider. Transmission Provider may also cure such Breach by funding the proportionate share of the Affected System Network Upgrade costs related to the Breach of Affected System Interconnection Customer. Transmission Provider must notify all Parties that it will exercise this option within thirty (30) Calendar Days of notification that an Affected System Interconnection Customer has failed to provide payments or security under Article 4.1.*

5.2.2 *In the event the Breach is not cured within the Cure Period, the Breaching Party will be in Default of this Agreement, and the non-Defaulting Parties may (1) act in concert to amend the Agreement to remove an Affected System Interconnection Customer that is in Default from this Agreement for cause and to make other changes as necessary, or (2) either in concert or individually take whatever action at law or in equity as may appear necessary or desirable to enforce the performance or observance of any rights, remedies, obligations, agreement, or covenants under this Agreement.*

5.3 Rights in the Event of Default. *Notwithstanding the foregoing, upon the occurrence of Default, the non-Defaulting Parties shall be entitled to exercise all rights and remedies it may have in equity or at law.*

ARTICLE 6
TERMINATION OF AGREEMENT

6.1 Expiration of Term. *Except as otherwise specified in this Article 6, the Parties' obligations under this Agreement shall terminate at the conclusion of the term of this Agreement.*

6.2 Termination and Removal. *Subject to the limitations set forth in Article 6.3, in the event of a Default, termination of this Agreement, as to a given Affected System Interconnection Customer or in its entirety, shall require a filing at FERC of a notice of termination, which filing must be accepted for filing by FERC.*

6.3 Disposition of Facilities Upon Termination of Agreement.

6.3.1 Transmission Provider Obligations. *Upon termination of this Agreement, unless otherwise agreed to by the Parties in writing, Transmission Provider:*

(a) shall, prior to the construction and installation of any portion of the Affected System Network Upgrade(s) and to the extent possible, cancel any pending orders of, or return, such equipment or material for such Affected System Network Upgrade(s);

(b) may keep in place any portion of the Affected System Network Upgrade(s) already constructed and installed; and,

(c) shall perform such work as may be necessary to ensure the safety of persons and property and to preserve the integrity of Transmission Provider's Transmission System (e.g., construction demobilization to return the system to its original state, wind-up work).

6.3.2 Affected System Interconnection Customer Obligations. *Upon billing by Transmission Provider, each Affected System Interconnection Customer shall reimburse Transmission Provider for its share of any costs incurred by Transmission Provider in performance of the actions required or permitted by Article 6.3.1 and for its share of the cost of any Affected System Network Upgrade(s) described in Appendix A. Transmission Provider shall use Reasonable Efforts to minimize costs and shall offset the amounts owed by any salvage value of facilities, if applicable. Each Affected System Interconnection Customer shall pay these costs pursuant to Article 4.3 of this Agreement.*

6.3.3 Pre-construction or Installation. *Upon termination of this Agreement and prior to the construction and installation of any portion of the Affected System Network Upgrade(s), Transmission Provider may, at its option, retain any portion of such Affected System Network Upgrade(s) not cancelled or returned in accordance with Article 6.3.1(a), in which case Transmission Provider shall be responsible for all costs*

associated with procuring such Affected System Network Upgrade(s). To the extent that an Affected System Interconnection Customer has already paid Transmission Provider for any or all of such costs, Transmission Provider shall refund Affected System Interconnection Customer for those payments. If Transmission Provider elects to not retain any portion of such facilities, and one or more of Affected System Interconnection Customers wish to purchase such facilities, Transmission Provider shall convey and make available to the applicable Affected System Interconnection Customer(s) such facilities as soon as practicable after Affected System Interconnection Customer(s)' payment for such facilities.

6.4 Survival of Rights. *Termination or expiration of this Agreement shall not relieve any Party of any of its liabilities and obligations arising hereunder prior to the date termination becomes effective, and each Party may take whatever judicial or administrative actions as appear necessary or desirable to enforce its rights hereunder. The applicable provisions of this Agreement will continue in effect after expiration, or early termination hereof, to the extent necessary to provide for (1) final billings, billing adjustments, and other billing procedures set forth in this Agreement; (2) the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and (3) the confidentiality provisions set forth in Article 8.*

ARTICLE 7
SUBCONTRACTORS

7.1 Subcontractors. *Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services, and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.*

7.1.1 Responsibility of Principal. *The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. In accordance with the provisions of this Agreement, each Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon a Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.*

7.1.2 No Third-Party Beneficiary. *Except as may be specifically set forth to the contrary herein, no subcontractor or any other party is intended to be, nor will it be deemed to be, a third-party beneficiary of this Agreement.*

7.1.3 No Limitation by Insurance. *The obligations under this Article 7 will not be limited in any way by any limitation of any insurance policies or coverages, including any subcontractor's insurance.*

ARTICLE 8
CONFIDENTIALITY

8.1 Confidentiality. *Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied to the other Parties prior to the execution of this Agreement.*

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential. The Parties shall maintain as confidential any information that is provided and identified by a Party as Critical Energy Infrastructure Information (CEII), as that term is defined in 18 CFR 388.113(c).

Such confidentiality will be maintained in accordance with this Article 8. If requested by the receiving Party, the disclosing Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

8.1.1 Term. *During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 8 or with regard to CEII, each Party shall hold in confidence and shall not disclose to any person Confidential Information. CEII shall be treated in accordance with FERC policies and regulations.*

8.1.2 Scope. *Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a non-Party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (6) is required, in accordance with Article 8.1.6 of this Agreement, to be disclosed by any Governmental Authority or is otherwise required to be*

disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the receiving Party that it no longer is confidential.

8.1.3 Release of Confidential Information. *No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, agents, consultants, or to non-Parties that may be or are considering providing financing to or equity participation with Affected System Interconnection Customer(s), or to potential purchasers or assignees of Affected System Interconnection Customer(s), on a need-to-know basis in connection with this Agreement, unless such person has first been advised of the confidentiality provisions of this Article 8 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 8.*

8.1.4 Rights. *Each Party shall retain all rights, title, and interest in the Confidential Information that it discloses to the receiving Party. The disclosure by a Party to the receiving Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.*

8.1.5 Standard of Care. *Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication, or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its regulatory requirements.*

8.1.6 Order of Disclosure. *If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the disclosing Party with prompt notice of such request(s) or requirement(s) so that the disclosing Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.*

8.1.7 Termination of Agreement. *Upon termination of this Agreement for any reason, each Party shall, within ten (10) Business Days of receipt of a written request from the*

other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the requesting Party) or return to the requesting Party any and all written or electronic Confidential Information received from the requesting Party, except that each Party may keep one copy for archival purposes, provided that the obligation to treat it as Confidential Information in accordance with this Article 8 shall survive such termination.

8.1.8 Remedies. *The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 8. Each Party accordingly agrees that the disclosing Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party Breaches or threatens to Breach its obligations under this Article 8, which equitable relief shall be granted without bond or proof of damages, and the Breaching Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 8, but it shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 8.*

8.1.9 Disclosure to FERC, its Staff, or a State Regulatory Body. *Notwithstanding anything in this Article 8 to the contrary, and pursuant to 18 CFR 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from a Party that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the Agreement when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.*

8.1.10 *Subject to the exception in Article 8.1.9, any information that a disclosing Party claims is competitively sensitive, commercial, or financial information under this Agreement shall not be disclosed by the receiving Party to any person not employed or retained by the receiving Party, except to the extent disclosure is (1) required by law; (2) reasonably deemed by the disclosing Party to be required to be disclosed in connection*

with a dispute between or among the Parties, or the defense of litigation or dispute; (3) otherwise permitted by consent of the disclosing Party, such consent not to be unreasonably withheld; or (4) necessary to fulfill its obligations under this Agreement or as Transmission Provider or a balancing authority, including disclosing the Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the receiving Party in writing of the information that Party claims is confidential. Prior to any disclosures of that Party's Confidential Information under this subparagraph, or if any non-Party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the Party that received the Confidential Information from the disclosing Party agrees to promptly notify the disclosing Party in writing and agrees to assert confidentiality and cooperate with the disclosing Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order, or other reasonable measures.

ARTICLE 9
INFORMATION ACCESS AND AUDIT RIGHTS

9.1 Information Access. *Each Party shall make available to the other Parties information necessary to verify the costs incurred by the other Parties for which the requesting Party is responsible under this Agreement and carry out obligations and responsibilities under this Agreement, provided that the Parties shall not use such information for purposes other than those set forth in this Article 9.1 and to enforce their rights under this Agreement.*

9.2 Audit Rights. *Subject to the requirements of confidentiality under Article 8 of this Agreement, the accounts and records related to the design, engineering, procurement, and construction of the Affected System Network Upgrade(s) shall be subject to audit during the period of this Agreement and for a period of twenty-four (24) months following Transmission Provider's issuance of a final invoice in accordance with Article 4.4. Affected System Interconnection Customers may, jointly or individually, at the expense of the requesting Party(ies), during normal business hours, and upon prior reasonable notice to Transmission Provider, audit such accounts and records. Any audit authorized by this Article 9.2 shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this Agreement.*

ARTICLE 10
NOTICES

10.1 General. *Any notice, demand, or request required or permitted to be given by a Party to the other Parties, and any instrument required or permitted to be tendered or delivered by a Party in writing to another Party, may be so given, tendered, or delivered, as the case may be, by depositing the same with the United States Postal Service with*

postage prepaid, for transmission by certified or registered mail, addressed to the Parties, or personally delivered to the Parties, at the address set out below:

To Transmission Provider:

To Affected System Interconnection Customers:

10.2 Billings and Payments. *Billings and payments shall be sent to the addresses shown in Article 10.1 unless otherwise agreed to by the Parties.*

10.3 Alternative Forms of Notice. *Any notice or request required or permitted to be given by a Party to the other Parties and not required by this Agreement to be given in writing may be so given by telephone, facsimile, or email to the telephone numbers and email addresses set out below:*

To Transmission Provider:

To Affected System Interconnection Customers:

10.4 Execution and Filing. *Affected System Interconnection Customers shall either: (i) execute two originals of this tendered Agreement and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC this Agreement in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of this tendered Agreement (if it does not conform with a FERC-approved standard form of this Agreement) or the request to file this Agreement unexecuted, Transmission Provider shall file this Agreement with FERC, together with its explanation of any matters as to which Affected System Interconnection Customers and Transmission Provider disagree and support for the costs that Transmission Provider proposes to charge to Affected System Interconnection Customers under this Agreement. An unexecuted version of this Agreement should contain terms and conditions deemed appropriate by Transmission Provider for the Affected System Interconnection Customers' generating facilities. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted version of this Agreement, they may proceed pending FERC action.*

ARTICLE 11
MISCELLANEOUS

11.1 *This Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability, and assignment, which reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of this LGIP.*

[Signature Page to Follow]

IN WITNESS WHEREOF, *the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original Agreement among the Parties.*

Transmission Provider
{Transmission Provider}
By: ______________________________
Name: ______________________________
Title: ______________________________

Affected System Interconnection Customer
{Affected System Interconnection Customer}
By: ______________________________
Name: ______________________________
Title: ______________________________

Project No. ____

Affected System Interconnection Customer
{Affected System Interconnection Customer}
By: ______________________________
Name: ______________________________
Title: ______________________________

Project No. ____

Attachment A to Appendix 12
Multiparty Affected System Facilities Construction Agreement

AFFECTED SYSTEM NETWORK UPGRADE(S), COST ESTIMATES AND RESPONSIBILITY, CONSTRUCTION SCHEDULE, AND MONTHLY PAYMENT SCHEDULE

This Appendix A is a part of the Multiparty Affected System Facilities Construction Agreement between Affected System Interconnection Customers and Transmission Provider.

1.1 Affected System Network Upgrade(s) to be installed by Transmission Provider.

{description}

1.2 First Equipment Order (including permitting).

{description}

1.2.1. Permitting and Land Rights – Transmission Provider Affected System Network Upgrade(s)

{description}

1.3 Construction Schedule. *Where applicable, construction of the Affected System Network Upgrade(s) is scheduled as follows and will be periodically updated as necessary:*

Table 3: Transmission Provider Construction Activities

MILESTONE NUMBER	***DESCRIPTION***	***START DATE***	***END DATE***

Note: Construction schedule assumes that Transmission Provider has obtained final authorizations and security from Affected System Interconnection Customers and all necessary permits from Governmental Authorities as necessary prerequisites to commence construction of any of the Affected System Network Upgrade(s).

1.4 Payment Schedule.

1.4.1 Timing of and Adjustments to Affected System Interconnection Customers' Payments and Security.
{description}

1.4.2 Monthly Payment Schedule. *Affected System Interconnection Customers' payment schedule is as follows.*

{description}

Table 4: Affected System Interconnection Customers' Payment/Security Obligations for Affected System Network Upgrade(s).

MILESTONE NUMBER	***DESCRIPTION***	***DATE***

** Affected System Interconnection Customers' proportionate responsibility for each payment is as follows:*

Affected System Interconnection Customer 1 ___._%
Affected System Interconnection Customer 2 ___._%
Affected System Interconnection Customer N ___._%

Note: Affected System Interconnection Customers' payment or provision of security as provided in this Agreement operates as a condition precedent to Transmission Provider's obligations to construct any Affected System Network Upgrade(s), and failure to meet this schedule will constitute a Breach pursuant to Article 5.1 of this Agreement.

1.5 Permits, Licenses, and Authorizations.

{description}

Attachment B to Appendix 12
Multiparty Affected System Facilities Construction Agreement

NOTIFICATION OF COMPLETED CONSTRUCTION

This Appendix B is a part of the Multiparty Affected System Facilities Construction Agreement among Affected System Interconnection Customers and Transmission Provider. Where applicable, when Transmission Provider has completed construction of the Affected System Network Upgrade(s), Transmission Provider shall send notice to Affected System Interconnection Customers in substantially the form following:

{Date}

{Affected System Interconnection Customers Addresses}

Re: Completion of Affected System Network Upgrade(s)

Dear {Name or Title}:

This letter is sent pursuant to the Multiparty Affected System Facilities Construction Agreement among {Transmission Provider} and {Affected System Interconnection Customers}, dated ____________, 20___.

On {Date}, Transmission Provider completed to its satisfaction all work on the Affected System Network Upgrade(s) required to facilitate the safe and reliable interconnection

and operation of Affected System Interconnection Customer's generating facilities. Transmission Provider confirms that the Affected System Network Upgrade(s) are in place.

Thank you.

{Signature}
{Transmission Provider Representative}

Attachment C to Appendix 12
Multiparty Affected System Facilities Construction Agreement

EXHIBITS

This Appendix C is a part of the Multiparty Affected System Facilities Construction Agreement among Affected System Interconnection Customers and Transmission Provider.

Exhibit A1
Transmission Provider Site Map

Exhibit A2
Site Plan

Exhibit A3
Affected System Network Upgrade(s) Plan & Profile

Exhibit A4
Estimated Cost of Affected System Network Upgrade(s)

	Location	***Facilities to Be Constructed by Transmission Provider***	***Estimate in Dollars***
		Total:	

Appendix D: *Pro forma* LGIA

Note: Deletions are in brackets and additions are in italics.

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ____ day of ___________ 20__, by and between _______________________, a _____________________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Interconnection Customer" with a Large Generating Facility), and ____, a _____________________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than [the] Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

[**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.]

Applicable Reliability Standards shall mean the requirements and guidelines of [NERC,]the [Applicable Reliability Council]*Electric Reliability Organization* and the [Control Area]*Balancing Authority Area* of the Transmission System to which the Generating Facility is directly interconnected.

Balancing Authority *shall mean an entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.*

Balancing Authority Area *shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.*

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by [the] Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Cluster *shall mean a group of one or more Interconnection Requests that are studied together for the purpose of conducting a Cluster Study.*

Cluster Restudy *shall mean a restudy of a Cluster Study conducted pursuant to Section 7.5 of the LGIP.*

Cluster Study *shall mean the evaluation of one or more Interconnection Requests within a Cluster as described in Section 7 of the LGIP.*

Clustering shall mean the process whereby *one or more* [a group of]Interconnection Requests [is] are studied together, instead of serially, [for the purpose of conducting the Interconnection System Impact Study]*as described in Section 7 of the LGIP.*

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Contingent Facilities *shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.*

[**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council.]

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Electric Reliability Organization *shall mean the North American Electric Reliability Corporation or its successor organization.*

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's

Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's [device] *device(s)* for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include [the]Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility [and] *or* the aggregate net capacity of the Generating Facility where it includes [multiple energy production devices] *more than one device for the production and/or storage for later injection of electricity*.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that

proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean [the]Transmission Provider's Interconnection Facilities and [the]Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to [the]Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by [the]Transmission Provider or a third party consultant for [the]Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the [Interconnection System Impact]*Cluster Study*), the cost of those facilities, and the time required to interconnect the Generating Facility with [the] Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of *the LGIP*[the Standard Large Generator Interconnection Procedures].

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix *3*[4] of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

[**Interconnection Feasibility Study** shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.]

[**Interconnection Feasibility Study Agreement** shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.]

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to *the LGIP* [the Standard Large Generator Interconnection Procedures], in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: [the Interconnection Feasibility Study, the Interconnection System Impact Study,] *the Cluster Study, the Cluster Restudy, the Surplus Interconnection Service System Impact Study*, and the Interconnection Facilities Study, described in *the LGIP* [the Standard Large Generator Interconnection Procedures].

[**Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.]

[**Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.]

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

***LGIA Deposit** shall mean the deposit Interconnection Customer submits when returning the executed LGIA, or within 10 Business Days of requesting that the LGIA be filed unexecuted at the Commission, in accordance with Section 11.3 of the LGIP.*

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a*n equal or* later *Queue Position*[queue priority date].

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

[NERC shall mean the North American Electric Reliability Council or its successor organization.]

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix *4*[5] of *the LGIP* [the Standard Large Generator Interconnection Procedures] for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Proportional Impact Method *shall mean a technical analysis conducted by Transmission Provider to determine the degree to which each Generating Facility in the Cluster Study contributes to the need for a specific System Network Upgrade.*

Provisional Interconnection Service shall mean Interconnection Service provided by Transmission Provider associated with interconnecting the Interconnection Customer’s Generating Facility to Transmission Provider’s Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff.

Provisional Large Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between Transmission Provider and/or the Transmission Owner and the Interconnection Customer. This agreement shall take the form of the Large Generator Interconnection Agreement, modified for provisional purposes.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, [that is] established *pursuant to*

Section 4.1 of the LGIP. [based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.]

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of [the]Interconnection Customer*(s)* and Transmission Provider conducted for the purpose of discussing *the proposed Interconnection Request and any* alternative interconnection options, [to]exchang[e]*ing* information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, *refining information and models provided by Interconnection Customer(s), discussing the Cluster Study materials posted to OASIS pursuant to Section 3.5 of the LGIP, and* [to]analyz[e]*ing* such information[, and to determine the potential feasible Points of Interconnection].

Site Control shall mean [documentation reasonably demonstrating] *the exclusive land right to develop, construct, operate, and maintain the Generating Facility over the term of expected operation of the Generating Facility. Site Control may be demonstrated by documentation establishing:* (1) ownership of, a leasehold interest in, or a right to develop a site [for the purpose of constructing]*of sufficient size to construct and operate* the Generating Facility*;* (2) an option to purchase or acquire a leasehold site *of sufficient size to construct and operate the Generating Facility* for such purpose; or (3) [an exclusivity or other business relationship between]*any other documentation that clearly demonstrates the right of Interconnection Customer*[and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or]to exclusively occupy a site [for such purpose.]*of sufficient size to construct and operate the Generating Facility. Transmission Provider will maintain acreage requirements for each Generating Facility type on its OASIS or public website.*

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction *and the following conditions are met: (1) a Substation Network Upgrade must only be required for a single Interconnection Customer in the Cluster and no other Interconnection Customer in that Cluster is required to interconnect to the same Substation Network Upgrades, and (2) a System Network Upgrade must only be required for a single Interconnection Customer in the Cluster, as indicated under Transmission Provider's*

Proportional Impact Method. Both [the]Transmission Provider and [the]Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If [the]Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, [the]Transmission Provider must provide [the]Interconnection Customer a written technical explanation outlining why [the]Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

Substation Network Upgrades *shall mean Network Upgrades that are required at the substation located at the Point of Interconnection.*

Surplus Interconnection Service shall mean any unneeded portion of Interconnection Service established in a Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Network Upgrades *shall mean Network Upgrades that are required beyond the substation located at the Point of Interconnection.*

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of

Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by [the]Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Withdrawal Penalty *shall mean the penalty assessed by Transmission Provider to an Interconnection Customer that chooses to withdraw or is deemed withdrawn from Transmission Provider's interconnection queue or whose Generating Facility does not otherwise reach Commercial Operation. The calculation of the Withdrawal Penalty is set forth in Section 3.7.1 of the LGIP.*

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that

Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 **Disconnection**. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 **Survival**. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

4.1.1 Energy Resource Interconnection Service.

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 Transmission Delivery Service Implications. Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection

Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

4.1.2 Network Resource Interconnection Service.

4.1.2.1 **The Product**. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 **Transmission Delivery Service Implications**. Network Resource Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis

as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 **Provision of Service**. Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 **Performance Standards**. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission

Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 **No Transmission Delivery Service**. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 **Interconnection Customer Provided Services**. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, & Construction

5.1 **Options**. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Standard Option or Alternate Option set forth below, and such dates and selected option shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.3 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Transmission Provider, the Interconnection Customer shall notify Transmission Provider within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

5.1.1 **Standard Option**. Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 Option to Build. Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of all facilities other than Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.3). If the Parties are unable to reach agreement on such terms and conditions, then pursuant to Article 5.1.1 (Standard Option), Transmission Provider shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of

Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.3, Interconnection Customer shall pay Transmission Provider the agreed upon amount of [$ PLACEHOLDER] for Transmission Provider to execute the responsibilities enumerated to Transmission Provider under Article 5.2. Transmission Provider shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for

which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers**. [The]Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the [Applicable Reliability Council]*Electric Reliability Organization*. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 **Equipment Procurement**. If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 **Construction Commencement**. Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 **Work Progress**. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified

In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Other Interconnection Options.

5.9.1 Limited Operation. If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.9.2 Provisional Interconnection Service. Upon the request of Interconnection Customer, and prior to completion of requisite Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities Transmission Provider may execute a Provisional Large Generator Interconnection Agreement or Interconnection Customer may request the filing of an unexecuted Provisional Large Generator Interconnection Agreement with the Interconnection Customer for limited Interconnection Service at the discretion of Transmission Provider based upon an evaluation that will consider the results of available studies. Transmission Provider shall determine, through available studies or additional studies as necessary, whether stability, short circuit, thermal, and/or voltage issues would arise if Interconnection Customer interconnects without modifications to the Generating Facility or Transmission System. Transmission Provider shall determine whether any Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities that are necessary to meet the requirements of [NERC] *the Electric Reliability Organization*, or any applicable Regional Entity for the interconnection of a new, modified and/or expanded Generating Facility are in place prior to the commencement of Interconnection Service from the Generating Facility. Where available studies indicate that such,

Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities that are required for the interconnection of a new, modified and/or expanded Generating Facility are not currently in place, Transmission Provider will perform a study, at the Interconnection Customer's expense, to confirm the facilities that are required for Provisional Interconnection Service. The maximum permissible output of the Generating Facility in the Provisional Large Generator Interconnection Agreement shall be studied and updated [on a frequency determined by Transmission Provider and at the Interconnection Customer's expense]. Interconnection Customer assumes all risk and liabilities with respect to changes between the Provisional Large Generator Interconnection Agreement and the Large Generator Interconnection Agreement, including changes in output limits and Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities cost responsibilities.

5.10 Interconnection Customer's Interconnection Facilities ('ICIF'). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's Review. Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications,

operational control, and safety requirements of Transmission Provider.

5.10.3 **ICIF Construction**. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 **Transmission Provider's Interconnection Facilities Construction**. Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 **Access Rights**. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect,

replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's

Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments

and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 **Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection

Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed

by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 **Private Letter Ruling or Change or Clarification of Law**. At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events**. If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades,

Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests**. In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the

current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any

reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 **Taxes Other Than Income Taxes**. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 **Transmission Owners Who Are Not Transmission Providers.** If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not

become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission

Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records

relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 General. Each Party shall comply with the[Applicable Reliability Council] *Electric Reliability Organization* requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 Testing of Metering Equipment. Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years.

Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 **Metering Data**. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 **Interconnection Customer Obligations**. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 Provision of Data from a Variable Energy Resource. The Interconnection Customer whose Generating Facility *contains at least one*[is] Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility *contains* [is] a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility *contains* [is] a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its

characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 General. Each Party shall comply with the[Applicable Reliability Council] *Electric Reliability Organization* requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 [Control Area]*Balancing Authority Area* Notification. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in writing of the [Control Area]*Balancing Authority Area* in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a[Control Area] *Balancing Authority Area* other than the [Control Area]*Balancing Authority Area* in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote [Control Area]*Balancing Authority Area* generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other [Control Area]*Balancing Authority Area*.

9.3 Transmission Provider Obligations. Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's

Interconnection Facilities in accordance with all applicable requirements of the [Control Area]*Balancing Authority Area* of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria.

9.6.1.1 Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless [the]Transmission Provider has established different requirements that apply to all synchronous generators in the [Control Area]*Balancing Authority Area* on a comparable basis.

9.6.1.2 Non-Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless[the] Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the [Control Area]*Balancing Authority Area* on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 Voltage Schedules. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the LargeGenerating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the [Control Area]*Balancing Authority Area* in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 **Voltage Regulators.** Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the [Control Area]*Balancing Authority Area* on a comparable basis.

9.6.3 Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer

provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection

Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 **Governor or Equivalent Controls**. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 **Timely and Sustained Response.** Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved [R]*r*eliability [S]*s*tandard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 **Exemptions.** Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4. **Electric Storage Resources.** Interconnection Customer interconnecting *a Generating Facility that contains* an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in

Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 **Outage Authority and Coordination**. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 **Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 **Outage Restoration**. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service**. If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer

of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 [Under-Frequency and Over Frequency Conditions]*Ride Through Capability and Performance.* The Transmission System is designed to automatically activate a load-shed program as required by the [Applicable Reliability Council]*Electric Reliability Organization* in the event of an underfrequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the[Applicable Reliability Council] *Electric Reliability Organization* to ensure *frequency* "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. *Interconnection Customer shall also implement under-voltage and over-voltage relay set points, or equivalent electronic controls, as required by the Electric Reliability Organization to ensure voltage "ride through" capability of the Transmission System.* The term "ride through" as used herein shall mean the ability of a Large Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency*,* [and]over-frequency*, under-voltage, and over-voltage* conditions, in accordance with Good Utility Practice *and consistent with any standards and guidelines that are applied to other Generating Facilities in the Balancing Authority Area on a comparable basis. For abnormal frequency conditions and voltage conditions within the "no trip zone" defined by Reliability Standard PRC-024-3 or successor mandatory ride through reliability standards, the non-synchronous Large Generating Facility must ensure that, within any physical limitations of the Large Generating Facility, its control and protection settings are configured or set to (1) continue active power production during disturbance and post disturbance periods at pre-disturbance levels, unless providing primary frequency response or fast*

frequency response; (2) minimize reductions in active power and remain within dynamic voltage and current limits, if reactive power priority mode is enabled, unless providing primary frequency response or fast frequency response; (3) not artificially limit dynamic reactive power capability during disturbances; and (4) return to pre-disturbance active power levels without artificial ramp rate limits if active power is reduced, unless providing primary frequency response or fast frequency response.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 **System Protection Facilities**. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by

Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as

amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations. Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 **Interconnection Customer Obligations**. Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 **Coordination**. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 **Secondary Systems**. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 **Operating and Maintenance Expenses**. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 **Interconnection Customer Interconnection Facilities**. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 **Transmission Provider's Interconnection Facilities**. Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. [The]Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by Interconnection Customer.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full

reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems**. Unless Transmission Provider provides, under the LGIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 **Provision of Security**. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment*, as specified in Appendix B of this LGIA*, shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of

Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes. *Transmission Provider must use the LGIA Deposit required in Section 11.3 of the LGIP before requiring Interconnection Customer to submit security in addition to that LGIA Deposit. Transmission Provider must specify, in Appendix B of this LGIA, the dates for which Interconnection Customer must provide additional security for construction of each discrete portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and Interconnection Customer must provide such additional security.*

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 **Interconnection Customer Compensation for Actions During Emergency Condition**. Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in

dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to**,** the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, [NERC,] the [Applicable Reliability Council]*Electric Reliability Organization*, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice. Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General. Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection. Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such,

reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing

in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty

(30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 **Right to Terminate**. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

17.2 ***Violation of Operating Assumptions for Generating Facilities.*** *If Transmission Provider requires Interconnection Customer to memorialize the operating assumptions for the charging behavior of a Generating Facility that includes at least one electric storage resource in Appendix H of this LGIA, Transmission Provider may consider Interconnection Customer to be in Breach of the LGIA if Interconnection Customer fails to operate the Generating Facility in accordance with those operating assumptions for charging behavior. However, if Interconnection Customer operates contrary to the operating assumptions for charging behavior specified in Appendix H of this LGIA at the direction of Transmission Provider, Transmission Provider shall not consider Interconnection Customer in Breach of this LGIA.*

Article 18. Indemnity, Consequential Damages and Insurance

18.1 **Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

18.1.1 **Indemnified Person**. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of

such claim, such Indemnified Person may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party**. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures**. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest

between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined

single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 **Assignment**. This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of

the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 **Term**. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 **Scope**. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information**. Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights**. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties**. By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care**. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure**. If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement**. Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the

other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies**. The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State**. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a [Control Area]*Balancing Authority Area* operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 **Information Acquisition**. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the [Feasibility]*Cluster Study* and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. [The]Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating

Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the

foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall

be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 **Good Standing**. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 **Authority**. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict**. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee. Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection

Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 **Conflicts**. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 **Rules of Interpretation**. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 **Entire Agreement**. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 **No Third Party Beneficiaries.** This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________ By: ______________________________

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

[Insert name of Interconnection Customer]

By: ______________________________

Title: ______________________________

Date: ______________________________

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

(a) {insert Interconnection Customer's Interconnection Facilities}:

(b) {insert Transmission Provider's Interconnection Facilities}:

2. Network Upgrades:

(a) {insert Stand Alone Network Upgrades}:

(b) {insert *Substation Network Upgrades* [Other Network Upgrades]}:

(c) {insert System Network Upgrades}:

3. Distribution Upgrades:

Appendix B to LGIA

Milestones

<u>Site Control</u>

Check box if applicable [ ]

Interconnection Customer with qualifying regulatory limitations must demonstrate 100% Site Control by {Transmission Provider to insert date 180 days from the effective date of this LGIA} or the LGIA may be terminated per Article 17 (Default) of this LGIA and the Interconnection Customer may be subject to Withdrawal Penalties per Section 3.7.1.1 of the Transmission Provider's LGIP (Calculation of the Withdrawal Penalty).

Appendix C to LGIA

Interconnection Details

Appendix D to LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Appendix E to LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

{Date}

{Transmission Provider Address}

Re: _____________ Large Generating Facility

Dear _______________:

On **{Date}** **{Interconnection Customer}** has completed Trial Operation of Unit No. ___. This letter confirms that {Interconnection Customer} commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **{Date plus one day}**.

Thank you.

{Signature}

{Interconnection Customer Representative}

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices:.

Transmission Provider:

{To be supplied.}

Interconnection Customer:

{To be supplied.}

Billings and Payments:

Transmission Provider:

{To be supplied.}

Interconnection Customer:

{To be supplied.}

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

{To be supplied.}

Interconnection Customer:

{To be supplied.}

APPENDIX G

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant or a Generating Facility that contains a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. <u>Technical Standards Applicable to a Wind Generating Plant</u>

i. <u>Low Voltage Ride-Through (LVRT) Capability</u>

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

<u>Transition Period LVRT Standard</u>

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and

single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer(i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective date of the Final Rule establishing the reactive power requirements for non-synchronous generators in *S*[s]ection 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's [System Impact] *Cluster* Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard

can be met by using, for example, power electronics designed to supply this level of reactive capability 606 (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. <u>Supervisory Control and Data Acquisition (SCADA) Capability</u>

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Appendix H to LGIA

Operating Assumptions for Generating Facility

Check box if applicable [ ]

Operating Assumptions:

{insert operating assumptions that reflect the charging behavior of the Generating Facility that includes at least one electric storage resource}

Appendix E: *Pro Forma* SGIP

Note: Deletions are in brackets and additions are in italics.

Section 1. Application

* * *

1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken. *Any such modification of the Interconnection Request must be accompanied by any resulting updates to the models described in Attachment 2 of this SGIP.*

* * *

Section 3. Study Process

* * *

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment 6).

3.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the

Interconnection Customer an executable interconnection agreement within five Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

3.3.6 The feasibility study shall evaluate static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, and tower lifting. Transmission Provider shall evaluate each identified alternative transmission technology and determine whether it should be used, consistent with Good Utility Practice and other applicable regulatory requirements. Transmission Provider shall include an explanation of the results of Transmission Provider's evaluation for each technology in the feasibility study report.

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

3.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the

scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, [the]Transmission Provider shall send [the]Interconnection Customer a distribution system impact study agreement.

3.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") – whether investor-owned or not – the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

3.4.10 The system impact study shall evaluate static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, and tower lifting. Transmission Provider shall evaluate each identified alternative transmission technology and determine whether it should be used, consistent with Good Utility Practice and other applicable regulatory requirements. Transmission Provider

shall include an explanation of the results of Transmission Provider's evaluation for each technology in the system impact study report.

* * *

Attachment 2
SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

* * *

Models for Non-synchronous Small Generating Facilities

For a non-synchronous Small Generating Facility, Interconnection Customer shall provide (1) a validated user-defined root mean squared (RMS) positive sequence dynamics model; (2) an appropriately parameterized generic library RMS positive sequence dynamics model, including model block diagram of the inverter control and plant control systems, as defined by the selection in Table 1 or a model otherwise approved by the Western Electricity Coordinating Council, that corresponds to Interconnection Customer's Small Generating Facility; and (3) if applicable, a validated electromagnetic transient model if Transmission Provider performs an electromagnetic transient study as part of the interconnection study process. A user-defined model is a set of programming code created by equipment manufacturers or developers that captures the latest features of controllers that are mainly software based and represents the entities' control strategies but does not necessarily correspond to any generic library model. Interconnection Customer must also demonstrate that the model is validated by providing evidence that the equipment behavior is consistent with the model behavior (e.g., an attestation from Interconnection Customer that the model accurately represents the entire Small Generating Facility; attestations from each equipment manufacturer that the user defined model accurately represents the component of the Small Generating Facility; or test data).

Table 1: Acceptable Generic Library RMS Positive Sequence Dynamics Models

GE PSLF	***Siemens PSS/E****	***PowerWorld Simulator***	***Description***
pvd1		*PVD1*	*Distributed PV system model*
der_a	*DERAU1*	*DER_A*	*Distributed energy resource model*
regc_a	*REGCAU1, REGCA1*	*REGC_A*	*Generator/converter model*

GE PSLF	***Siemens PSS/E****	***PowerWorld Simulator***	***Description***
regc_b	*REGCBU1*	*REGC_B*	*Generator/converter model*
wt1g	*WT1G1*	*WT1G and WT1G1*	*Wind turbine model for Type-1 wind turbines (conventional directly connected induction generator)*
wt2g	*WT2G1*	*WT2G and WT2G1*	*Generator model for generic Type-2 wind turbines*
wt2e	*WT2E1*	*WT2E and WT2E1*	*Rotor resistance control model for wound-rotor induction wind-turbine generator wt2g*
reec_a	*REECAU1, REECA1*	*REEC_A*	*Renewable energy electrical control model*
reec_c	*REECCU1*	*REEC_C*	*Electrical control model for battery energy storage system*
reec_d	*REECDU1*	*REEC_D*	*Renewable energy electrical control model*
wt1t	*WT12T1*	*WT1T and WT12T1*	*Wind turbine model for Type-1 wind turbines (conventional directly connected induction generator)*
wt1p_b	*wt1p_b*	*WT12A1U_B*	*Generic wind turbine pitch controller for WTGs of Types 1 and 2*
wt2t	*WT12T1*	*WT2T*	*Wind turbine model for Type-2 wind turbines (directly connected induction generator wind turbines with an external rotor resistance)*
wtgt_a	*WTDTAU1, WTDTA1*	*WTGT_A*	*Wind turbine drive train model*
wtga_a	*WTARAU1, WTARA1*	*WTGA_A*	*Simple aerodynamic model*
wtgp_a	*WTPTAU1, WTPTA1*	*WTGPT_A*	*Wind Turbine Generator Pitch controller*
wtgq_a	*WTTQAU1, WTTQA1*	*WTGTRQ_A*	*Wind Turbine Generator Torque controller*
wtgwgo_a	*WTGWGOAU*	*WTGWGO_A*	*Supplementary control model for Weak Grids*
wtgibffr_a	*WTGIBFFRA*	*WTGIBFFR_A*	*Inertial-base fast frequency response control*
wtgp_b	*WTPTBU1*	*WTGPT_B*	*Wind Turbine Generator Pitch controller*

GE PSLF	***Siemens PSS/E****	***PowerWorld Simulator***	***Description***
wtgt_b	*WTDTBU1*	*WTGT_B*	*Drive train model*
repc_a	*Type 4: REPCAU1 (v33), REPCA1 (v34)* *Type 3: REPCTAU1 (v33), REPCTA1 (v34)*	*REPC_A*	*Power Plant Controller*
repc_b	*PLNTBU1*	*REPC_B*	*Power Plant Level Controller for controlling several plants/devices* *In regard to Siemens PSS/E*:* *Names of other models for interface with other devices: REA3XBU1, REAX4BU1- for interface with Type 3 and 4 renewable machines* *SWSAXBU1- for interface with SVC (modeled as switched shunt in powerflow)* *SYNAXBU1- for interface with synchronous condenser* *FCTAXBU1- for interface with FACTS device*
repc_c	*REPCCU*	*REPC_C*	*Power plant controller*

*   *   *

Appendix F: *Pro Forma* SGIA

Note: Deletions are in brackets and additions are in italics.

* * *

Article 1. Scope and Limitations of Agreement.

* * *

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Transmission Provider shall construct, operate, and maintain its Transmission System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Transmission Provider and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall

be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Transmission Provider and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Transmission Provider's Transmission System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Transmission Provider shall coordinate with all Affected Systems to support the interconnection.

1.5.7 The Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to *S*[s]ection 2.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The Small Generating Facility’s protective equipment settings shall comply with the Transmission Provider’s automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term “ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term “frequency ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term “voltage ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the

system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. *For abnormal frequency conditions and voltage conditions within the "no trip zone" defined by Reliability Standard PRC-024-3 or successor mandatory ride through Applicable Reliability Standards, the non-synchronous Small Generating Facility must ensure that, within any physical limitations of the Small Generating Facility, its control and protection settings are configured or set to (1) continue active power production during disturbance and post disturbance periods at pre-disturbance levels unless providing primary frequency response or fast frequency response; (2) minimize reductions in active power and remain within dynamic voltage and current limits, if reactive power priority mode is enabled, unless providing primary frequency response or fast frequency response; (3) not artificially limit dynamic reactive power capability during disturbances; and (4) return to pre-disturbance active power levels without artificial ramp rate limits if active power is reduced, unless providing primary frequency response or fast frequency response.*

1.6 Parallel Operation Obligations. Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable [control area]*Balancing Authority Area*, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the Tariff or by the applicable system operator(s) for the Transmission Provider's Transmission System and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement.

* * *

1.8 Reactive Power and Primary Frequency Response

1.8.1 Power Factor Design Criteria

1.8.1.1 Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated

synchronous generators in the [control area]*Balancing Authority Area* on a comparable basis.

1.8.1.2 Non-Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all similarly situated non-synchronous generators in the [control area]*Balancing Authority Area* on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

1.8.2 The Transmission Provider is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Small Generating Facility when the Transmission Provider requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in *A*[a]rticle 1.8.1. In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

1.8.3 Payments shall be in accordance with the Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of the Commission's prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

1.8.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Small Generating Facility by

installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Small Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Sections 1.8.4.1 and 1.8.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities.

<u>1.8.4.1 Governor or Equivalent Controls.</u> Whenever the Small Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Small Generating

Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant [b]*B*alancing [a]*A*uthority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved [NERC] *Electric Reliability Organization* [R]*r*eliability [S]*s*tandard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant [b]*B*alancing [a]*A*uthority upon request. If Interconnection Customer needs to operate the Small Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant [b]*B*alancing [a]*A*uthority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Small Generating Facility's governor or equivalent controls to a minimum whenever the Small Generating Facility is operated in parallel with the Transmission System.

1.8.4.2 <u>Timely and Sustained Response.</u> Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Small Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls.

A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

1.8.4.3 Exemptions. Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 1.8.4, 1.8.4.1, and 1.8.4.2 of this Agreement. Small Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 1.8.4, but shall be otherwise exempt from the operating requirements in Sections 1.8.4, 1.8.4.1, 1.8.4.2, and 1.8.4.4 of this Agreement.

1.8.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Attachment 5 of its SGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 1.8.4, 1.8.4.1, 1.8.4.2 and 1.8.4.3 of this Agreement. Attachment 5 shall specify whether the operating range is static or dynamic, and shall consider: (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or [b]*B*alancing [a]*A*uthority as appropriate. If the operating range is dynamic, then Attachment 5 must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 1.8.4.2 of this Agreement when it is online and

dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

* * *

Attachment 1

Glossary of Terms

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Balancing Authority *shall mean an entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.*

Balancing Authority Area *shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.*

Business Day – Monday through Friday, excluding Federal Holidays.

Default – The failure of a breaching Party to cure its breach under the Small Generator Interconnection Agreement.

Distribution System – The Transmission Provider's facilities and equipment used to

transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Interconnection Provider, or any Affiliate thereof.

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of,

or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider’s Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider’s Transmission System to accommodate the interconnection of the Small Generating Facility with the Transmission Provider’s Transmission System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, Independent System Operator, [control area]*Balancing Authority Area*, or [the]Transmission Providers requirements, including those set forth in the Small Generator Interconnection Agreement.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the Small Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Tariff – The Transmission Provider or Affected System's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider – The public utility (or its designated agent) that owns, controls,

or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System – The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades – The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements — Docket No. RM22-14-000

(Issued July 28, 2023)

DANLY, Commissioner, *concurring*:

1. I concur in the issuance of today's final rule. I write separately to state that, while I continue to harbor misgivings about the Commission's power to implement far-reaching, uniform policies based on our authority under FPA section 206,[1] I am satisfied on this record that existing interconnection procedures in both RTO and non-RTO regions have been shown to be unjust and unreasonable, and that we take today's action consistent with the standards articulated in precedent.[2] Though I am not convinced that this precedent will ultimately be proven correct in declaring that "the Commission may rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution," the Commission is entitled to act under prevailing case law.[3]

2. I also agree that the relatively narrow reforms contemplated in this final rule appear, based on this record, to be a just and reasonable replacement rate. I am pleased that most of that which I considered to be the most problematic elements in the Notice of Proposed Rulemaking have been excluded from this rule.[4] I also remind parties of the availability of "the independent entity variation standard for regional transmission organizations (RTO) and independent system operators (ISO) and the consistent with or

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[1] 16 U.S.C. § 824e.

[2] *Improvements to Generator Interconnection Procedures & Agreements*, 184 FERC ¶ 61,054, at P 57 & n.149 (2023) (Interconnection Rule) (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 67 (D.C. Cir. 2014) (quoting *Interstate Nat. Gas Ass'n v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002))).

[3] *Id.*

[4] *Improvements to Generator Interconnection Procedures & Agreements*, 179 FERC ¶ 61,194 (2022) (Danly, Comm'r, concurring at PP 6-10) (NOPR Concurrence).

superior to standard for non-RTO/ISO transmission providers" should they choose to seek variations from these rules.[5]

3. While I vote to approve today's order, I will also thoroughly review any requests for rehearing, particularly to the extent to which parties to the proceeding wish to advance arguments that we have exceeded our authority under FPA section 206, or that we have failed to carry our evidentiary burden, either generally, or in a sufficient number of specific cases that our order amounts to an unlawful exercise of our powers.

4. I would have preferred to receive section 205[6] filings from utilities proposing interconnection reforms—and indeed we have received and ruled upon a number of such filings. Failing that, I would have preferred for the Commission or interested parties to have initiated FPA section 206 complaints against the RTOs or other entities with interconnection delays, rather than to have proceeded generically in an effort to establish uniformity.[7] However, my preferences do not make this rule unlawful, and I am satisfied that today's rule is consistent with our legal obligations.

For these reasons, I respectfully concur.

____
James P. Danly
Commissioner

[5] Interconnection Rule, 184 FERC ¶ 61,054 at P 10 (citation omitted).

[6] 16 U.S.C. § 824d.

[7] *See* NOPR Concurrence at PP 1, 4.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements — Docket No. RM22-14-000

(Issued July 28, 2023)

CLEMENTS, Commissioner, *concurring*:

1. As the findings of this final rule illustrate, our nation is facing a grid infrastructure crisis. Five years ago, the Commission issued Order No. 845 in an effort to improve interconnection queue delays, noting that "despite Commission efforts to improve the interconnection process . . . many interconnection customers experience delays, and some interconnection queues have significant backlogs and long timelines."[1] Unfortunately, the same observation can be made today, only the problem has gotten far worse.[2] As of the end of 2022, a staggering 10,000 projects representing over 2,000 GW of potential generation and storage capacity are stuck in line to connect to the grid.[3] That is nearly double the 1,250 GW of total installed capacity in the United States today.[4] Wait times have "increased markedly," with Lawrence Berkeley National Lab reporting that "[t]he typical project built in 2022 took 5 years from the interconnection request to commercial operations, compared to 3 years in 2015 and [less than] 2 years in 2008."[5] Meanwhile,

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[1] *Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 83 FR 21342 (May 9, 2018), 163 FERC ¶ 61,043, at P 24 (2018), *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, 84 FR 8156 (Mar. 6, 2019), *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

[2] *See Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054, at PP 37-40 (2023) [hereinafter Final Rule].

[3] Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022*, at 7-8 (Apr. 2023), https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf [hereinafter Queued Up 2023].

[4] *Id.* at 10.

[5] *Id.* at 3.

interconnection costs have increased significantly.[6] Project completion rates are very low,[7] and late-stage withdrawal is becoming more common.[8] In addition, the typical timespan between the execution of a project's interconnection agreement and its commercial operations date has also increased, from roughly 17 months for projects built between 2007-2014 to around 22 months for projects built between 2015-2022.[9]

2. Ultimately, the dysfunction of the interconnection process harms consumers. It prevents low-cost generation from coming online that could have reduced the cost of electricity,[10] and it harms reliability. Several of the nation's largest grid operators have stated that they could face resource adequacy problems if new resource entry does not occur rapidly enough to match the pace of resource retirements.[11] Given these challenges and their attendant impacts on consumers, I enthusiastically support this final rule, which includes a number of helpful reforms that will improve interconnection processes across the country. The bulk of these reforms will widely extend proven best practices to utilities around the country.

3. What we have learned through consideration of comments to and stakeholder engagement about the Commission's Notice of Proposed Rulemaking, however, is that

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[6] *See* Final Rule at P 41 (detailing interconnection cost increases seen across different regions).

[7] *See* Queued Up 2023 at 18-20.

[8] *Id.* at 22.

[9] *Id.* at 30.

[10] *See, e.g.*, T. Bruce Tsuchida et al., The Brattle Grp., *Unlocking the Queue with Grid-Enhancing Technologies: Case Study of the Southwest Power Pool* at 9 (Feb. 1, 2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf (estimating that integrating 2,670 MW of new generation in the Southwest Power Pool would yield annual production cost savings of $175 million).

[11] *See* PJM Interconnection, LLC, *Energy Transition in PJM: Resource Retirements, Replacements & Risks* at 2 (Feb. 24, 2023), energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx; Midcontinent Indep. Sys. Operator, *2022 Regional Resource Assessment* at 4, 20 (Nov. 2022), https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf; California Indep. Sys. Operator, *Summer Loads and Resources Assessment* at 20 (May 18, 2022), http://www.caiso.com/Documents/2022-Summer-Loads-and-Resources-Assessment.pdf.

while this rule can be expected to improve matters, more will be necessary to solve the problem. What was perhaps considered a straightforward kitchen renovation has become more complicated. After we have removed the cabinets and taken out the drywall, we have discovered outdated wires, rusted pipes and cracks in the foundation. None of these additional challenges are insurmountable, but they are in some ways more fundamental to getting that modern, working kitchen up and running.

4. I therefore write separately to highlight some of the remaining issues and potential solutions parties have brought forward that may address the remainder of the full interconnection reform challenge, as well as to encourage stakeholders to remain focused on taking additional critical steps toward addressing these issues.

5. I do not suggest that solving the remaining challenges related to interconnection will be easy. The record reveals quite the opposite. A comprehensive solution set will require out-of-the-box thinking in some areas and continued incremental improvements in others.

6. Fortunately, we have received many thoughtful suggestions for further reforms, which serve as the seeds for future solutions. Below, I discuss two categories of promising ideas meriting further discussion: (1) deeper reforms that get at some of the remaining fundamental challenges with interconnection processes; and (2) additional nuts and bolts changes that could enhance the effectiveness of a variety of interconnection processes, but which were not part of the proposal giving rise to this final rule.

7. I urge stakeholders to examine these and related suggestions, and for transmission planners to adopt regionally appropriate solutions beyond those required by this final rule.

I. Deeper reforms

8. In considering interconnection processes across the country, twin challenges emerge as the most fundamental problems. First, interconnection studies initially examine clusters of projects that often bear little resemblance to what ultimately interconnects to the system. They rely on a long and painful process of attrition to arrive at a final set of projects along with corresponding network upgrades.

9. More specifically, processes that rely solely on interconnection applications to determine study scope, and which require substantial study work for each customer based on inputs that depend on other projects in the queue, have become overwhelmed. For example, S&P reports that the California Independent System Operator (CAISO) received more than 350 GW of projects in its latest application window, driving its total

queue to over 500 GW.[12] Meanwhile, the Midcontinent Independent System Operator's (MISO) queue has ballooned to 339 GW, while PJM Interconnection, LLC's (PJM) has risen to 298 GW, both comfortably greater than the present installed capacity of either region.[13] According to a recent CAISO stakeholder presentation, "[t]he massive increase in interconnection requests seeking to meet the accelerated cadence of resource development . . . has overwhelmed critical planning and engineering resources across the industry. . . . The current generator interconnection processes simply cannot efficiently accommodate the latest level of interconnection requests received."[14] Other queues are similarly overwhelmed.[15]

10. Second, project developers face enormous cost uncertainty.[16] Initial study results may be far different from final costs because the number of projects reaching the facilities study stage (the final stage before the execution of a generator interconnection agreement) can be far fewer than those earlier examined in the cluster study stage. As CAISO observed in a recent stakeholder presentation, its "[s]tudy results lose accuracy, meaning and utility when the level of cluster [Interconnection Resource] capacity [is] multiple times the existing or planned transmission capacity for an area."[17]

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[12] Garrett Hering, *California ISO Tackles 'Broken' Interconnection Process as Queue Tops 500 GW*, S&P GLOBAL (July 19, 2023); *see also* CAISO, *Cluster 15 Interconnection Requests*, http://www.caiso.com/planning/Pages/Generator Interconnection/Default.aspx (last visited July 26, 2023).

[13] Queued Up 2023 at 9-10.

[14] CAISO, *2023 Interconnection Process Enhancements: Summary of June 20 & 21 Track 2 Working Group Meeting – Revised Principles and Problem Statements 1 and 2*, at 4 (June 23, 2023), http://www.caiso.com/InitiativeDocuments/Revised-Principles-and-Problem-Statements-Interconnection-Process-Enhancements-2023-Track %202-Jun%2020-212023.pdf.

[15] *See* Queued Up 2023 at 9 (showing very large amounts of queue capacity across several regions).

[16] *See* Final Rule at P 43 ("Cost uncertainty poses an especially significant obstacle because interconnection customers may not be able to finance substantial increases in unexpected interconnection costs."). For example, in one relatively recent interconnection cluster in MISO, the preliminary system impact study estimated $3.2 billion in network upgrades for 31 projects, but that estimate was cut to only $330 million by Decision Point I after more than half of the projects withdrew. *See Midcontinent Indep. Sys. Operator*, 169 FERC ¶ 61,173, at P 11 (2019).

[17] CAISO, *2023 Interconnection Process Enhancements Track 2 Working Group*

11. Today's final rule will help to ameliorate these problems. In particular, the rule's site control requirements,[18] requirement for an interconnection customer to select a definitive point of interconnection,[19] commercial readiness requirements,[20] and withdrawal penalty framework[21] will each contribute to more streamlined study clusters. As we have learned through this proceeding, however, they will likely be inadequate, on their own, to fully solve these deep challenges.[22]

12. In my estimation, the record of this proceeding, as well as recent stakeholder initiatives, suggest several options for further improvement. They are not necessarily exclusive of one another, and appropriate application may depend on the particular regional context. They include: (1) linking the interconnection process to proactive transmission system planning; (2) in applicable regions, aligning the interconnection process more closely with competitive resource solicitations; and (3) transitioning to a "focused" interconnection process or "connect and manage" approach for all energy-only resources.

A. **<u>Link the interconnection process to proactive transmission system planning</u>**

13. Foundationally, it should be acknowledged that for interconnection reform to succeed, holistic, forward-looking transmission planning, as included in the

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at 10 (July 11, 2023), http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track-2-Working-Group-Jul112023.pdf.

[18] *See* Final Rule at PP 583-612.

[19] *Id.* at PP 200-03.

[20] *Id.* at PP 690-707.

[21] *Id.* at PP 780-813].

[22] The Arizona Corporation Commission, for example, argues that '"first-ready' queue reforms that are not explicitly linked to an effective rationing process will likely fail to help resolve the growing backlog. Some mechanism to prioritize projects and allocate scarce interconnection access to the highest quality projects is likely needed." Arizona Commission Initial Comments at 1-2. Similarly, a coalition of consumer groups and the R Street Institute argues that the Commission's notice of proposed rulemaking in this proceeding "leaves many critical reforms unresolved." R Street Institute et al. June 8, 2023 Comments in Support of Generator Interconnection Reform Under RM22-14, at 2. *See also* Cypress Creek Initial Comments at 12 (arguing that "a cluster-based approach alone, without further changes, will not provide adequate reform").

Commission's notice of proposed rulemaking on regional planning and cost allocation,[23] must also succeed. Interconnection processes are overloaded in part because they are being relied on to build out core transmission system infrastructure that should be considered in regional planning processes. We know interconnection processes were not intended for, and are ill suited to perform, this task. As a coalition of consumer groups and the R Street Institute argues in a recent letter to the Commission, "[t]he cost of network upgrades can be dramatically reduced through proactive regional transmission planning, which enables major reductions in [Generator Interconnection] requirements and delays."[24] Even prior to the adoption of any final rule in the Commission's regional transmission planning proceeding, individual transmission providers can make significant strides toward the cost-effective construction of new transmission infrastructure via regionally tailored proposals and initiatives.[25]

14. There may also be opportunities to streamline the interconnection process by more closely linking it to the transmission system planning process,[26] or to carry out forward-looking interconnection studies driven by a more holistic assessment of interconnection needs.

15. Southwest Power Pool (SPP) and its stakeholders have embarked on a potentially promising initiative along these lines, which proposes a "Consolidated Planning Process" that would connect SPP's interconnection process to its regional transmission planning process.[27] Similarly, CAISO is seeking to "[p]rioritize interconnection in zones where

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[23] *See Building for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

[24] R Street Institute et al. June 8, 2023 Comments in Support of Generator Interconnection Reform Under RM22-14, at 2.

[25] *See, e.g.*, MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary* at 1 (2022), https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf (describing a proposed "portfolio of 18 transmission projects located in the MISO Midwest Subregions with a total investment of $10.3 billion, and benefit-to-cost ratios average of 2.6").

[26] *See, e.g.*, AEE Initial Comments at 10-13 (advocating for a closer linkage between transmission planning and generator interconnection).

[27] *See* Southwest Power Pool, *Consolidated Planning Process Task Force*, https://www.spp.org/stakeholder-groups-list/organizational-groups/board-of-directorsmembers-committee/consolidated-planning-process-task-force/ (last visited July 26, 2023); Southwest Power Pool, *Consolidated Planning Process: Phase 1*

transmission capacity exists or new transmission has been approved, while providing opportunities to identify and provide alternative points of interconnection or upgrades."[28] Like SPP, CAISO aims to overhaul a bloated queue that requires initial studies that bear little relation to transmission system reality, and instead chart a course to a new process that produces "meaningful study results that take into account system capability, resource planning and procurement."[29]

16. The promise of a forward-looking approach is also becoming clear through the ongoing effort that MISO and SPP are pioneering in the affected systems context. That effort, known as the Joint Targeted Interconnection Queue (JTIQ), examines a larger portfolio of projects to identify solutions that more efficiently solve their collective

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Recommendations (May 17, 2023), https://www.spp.org/spp-documents-filings/?id=297513 (when accessing "CPPTF Meeting Materials 20230621"). SPP proposes to calculate an "entry fee," which would involve per-MW costs of any "regional" or "sub-regional" interconnection network infrastructure, along with a "local" component derived from a narrower reliability assessment examining any necessary facilities at the point of interconnection. *See* Southwest Power Pool, *CPP Entry Fee Rate Structure*, at 20 (July 14, 2023), https://www.spp.org/spp-documents-filings/?id=297513 (when accessing "CPPTF Meeting Materials 20230714") (setting forth entry fee components). The key to SPP's proposal, as I understand it, is that the regional and sub-regional components of the entry fee would be identified by "forward-casting," a "longer-term assessment" derived from estimated costs of interconnecting resources in a fashion that is integrated with SPP's long-term regional plan. *Id.* By assessing costs across a broader range of projects than any individual cluster, and by calculating it based on SPP's proactive planning vision rather than calculating costs for a hypothetical cluster of initial applicants that will not all reach commercial operation, SPP may be able to offer far greater cost certainty for project developers and thereby greatly streamline and accelerate the interconnection process. *Id.* at 11, 19 (illustrating a greatly simplified flow chart for the consolidated planning approach as compared to SPP's status quo).

[28] CAISO, *2023 Interconnection Process Enhancements Track 2 Working Group* at 9 (July 11, 2023), http://www.caiso.com/InitiativeDocuments/Presentation-Interconnection-Process-Enhancements-2023-Track-2-Working-Group-Jul112023.pdf.

[29] *Id.*

needs.[30] By assessing larger, long-term system needs across study clusters, this approach identifies efficiencies that could not be captured on a more project-specific basis.[31]

17. As these regions' proposals are still in flux and have yet to be filed with the Commission, I do not prejudge them. But, at a high level, it appears that these types of approaches may hold the potential to provide developers more certainty; avoid a dynamic whereby large upgrades are assigned to individual projects that then drop from the queue, causing a cascading need for restudy; and deliver benefits to consumers by identifying more efficient infrastructure solutions than would be delivered on a piecemeal basis.

18. Questions worth exploring as these types of processes develop include:

a. How can the process ensure that fees charged to interconnection customers provide the funds needed for the relevant proactively-planned network upgrades, while providing developers with a reasonable degree of cost certainty?;

b. Would a mechanism such as a competitive auction or open season administered by the transmission provider be an effective tool for allocating scarce interconnection capacity identified by the forward-looking plans, and/or are there other processes that can effectively streamline the study process?;

c. How can such processes be designed in a manner that is not unduly discriminatory and is consistent with open access principles?; and

d. What process is appropriate for interconnection applications that do not align with the transmission provider's forward-looking regional transmission plan?

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[30] *See generally* SPP & MISO, *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes White Paper* (Dec. 20, 2022), https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf. Because this approach looks at projects that have reached the affected systems study stage, it does not provide a template for narrowing the initial pool of projects to facilitate meaningful study results. But the forward-looking nature of the initiative may nevertheless provide valuable insights to regional interconnection processes more broadly.

[31] *See* SPP & MISO, *MISO-SPP Joint Targeted Interconnection Queue Update* at 7 (March 27, 2023), https://cdn.misoenergy.org/20230337%20MISO%20SPP%20JTIQ%20Update628357.pdf.

B. Align interconnection processes with competitive resource solicitations

19. In some regions of the country, it may be appropriate to link aspects of the interconnection process to resource solicitation.[32] The Colorado Public Utilities Commission (Colorado Commission), for example, characterizes the interconnection queue management processes of transmission providers in its state as "highly functional."[33] The key, it says, is that its "existing FERC-approved tariffs and bilateral market structure . . . ensures that projects selected in [its] competitive resource planning and acquisition process obtain scarce interconnection in a cost-effective and timely manner."[34]

20. The Colorado Commission and Arizona Corporation Commission (Arizona Commission) argue that a mechanism to allocate scarce interconnection capacity is needed.[35] The Colorado Commission explains that if there is 400 MW of low-cost headroom on the system, for instance, several commercially viable projects that collectively exceed that amount may compete for that headroom yet be unviable on a collective basis if all proceed.[36] It contends that, lacking a mechanism to allocate the headroom, a cluster study process may result in an inefficient cycle of study, re-study and delay, without necessarily ensuring that the 400 MW of headroom is used efficiently.[37] It argues that facilitating a process where state-jurisdictional competitive solicitation can be used to allocate scarce interconnection capacity is appropriate given "state priorities involving reliability, customer, and environmental preferences."[38]

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[32] *See, e.g.*, Clean Energy Associations Initial Comments at 38 (urging the acceptance of "regionally specific proposals that would align the interconnection process with competitive procurements associated with resource planning, rather than placing them at odds"). Such alignment may not be appropriate or feasible, of course, in certain multi-state regions in which the bulk of resource development is driven by anticipated market revenues.

[33] Colorado Commission Initial Comments at 2.

[34] *Id.*

[35] Arizona Commission Initial Comments at 1-2; Colorado Commission Initial Comments at 21-27.

[36] Colorado Commission Initial Comments at 21-27.

[37] *Id.*

[38] *Id.* at 29.

21. FERC proposed a similar "optional resource solicitation" study in this proceeding. Our proposed process differed in a critical respect: the resource solicitation was not granted a queue position,[39] and being selected in the resource solicitation would not serve as a mechanism for allocating scarce interconnection capacity. The possibility of more comprehensively aligning the interconnection process with competitive resource solicitations (beyond the jurisdictions where such an approach is currently used) raises many questions, such as:

a. How can competitive solicitations and interconnection processes be designed to effectively coordinate with one another, especially where the soliciting entity (e.g., a state) is different from the transmission provider (e.g., an RTO)?

b. To be effective as a mechanism to allocate scarce interconnection capacity, must a competitive solicitation be paired with a mechanism such as further strengthened commercial readiness requirements to limit the pool of resources in the queue not responding to solicitations, or be designed in a fashion that limits the interactions in the study process between resources responding to the relevant solicitation(s) and those that do not?[40] Can such requirements be designed in a manner that is not unduly discriminatory, and if so, how?

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[39] Commenters argue that the Commission should have proposed to grant a queue position to the resource solicitation. *See, e.g.*, Colorado Commission Reply Comments at 6; EEI Initial Comments at 5-6; Xcel Initial Comments at 11-14; Clean Energy Associations Initial Comments at 51. Without a queue position for the resource solicitation, the costs identified in the study may not hold true for the various queue positions of underlying resources.

[40] The Colorado Commission argues that if projects to be studied as part of a competitive solicitation request are "comingled with a much broader pool of speculative projects," the process could become "unworkable." Colorado Commission Reply Comments at 5. It argues that, in the RTO context, commercial readiness requirements will be inadequate for this task, and suggests that the Commission allow transmission providers to prioritize native load, using solicitations as a mechanism to allocate scarce interconnection capacity. *See* Colorado Commission Initial Comments at 21-30. In contrast, the Interwest Energy Alliance argues that while competitive resource solicitations could be a useful tool to organize a portion of the interconnection process, they should not "becom[e] the only pathway through the cluster study process," because "alternative pathways with reasonable commercial readiness requirements may . . . reveal opportunities for independent transmission companies (potentially associated with independent generation developers) to discover cost-effective ways to add much-needed transmission expansion through additional lines along with additional interconnection capacity." Interwest Initial Comments at 11-12. Alternatives may be available that allow for other development opportunities alongside resources solicitation clusters. For

c. Are safeguards necessary to render not unduly discriminatory an interconnection process closely linked to a competitive solicitation process, and if so, what safeguards are necessary or appropriate?[41]

d. Is linking the interconnection process to competitive solicitations a viable option in RTO regions, in which state solicitation processes play a large role in supporting new market entrants but other paths to commercial viability may also exist?

C. Facilitate a "focused" interconnection process

22. Other promising ideas for improving cost certainty and reducing delays were put forward to the Commission in this proceeding. In particular, several commenters endorse a more "focused" interconnection process that streamlines study scope and reduces the need for restudies for projects requesting energy-only service.[42] As Enel observes, the

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example, a resource solicitation might be granted its own cluster (so as to allow the soliciting entity to understand the interconnection costs for its combination of resources), while providing for serial processing of clusters composed of resources not participating in the resource solicitation. *See* Enel Initial Comments at 72 (arguing that if the Commission were to adopt an optional resource solicitation process that designated a queue position, it "should be a separate queue cycle with an intermediate queue priority between the Transmission Provider's annual study clusters").

[41] Several entities highlighted the need for guardrails to prevent undue discrimination with regard to the Commission's proposal of an optional resource solicitation study. *See, e.g.*, R Street Initial Comments at 15-16 ("Guardrails may be helpful to prevent inefficiencies, preference or undue discrimination"); NARUC Initial Comments at 26 ("NARUC strongly supports FERC's proposal to limit the applicability of the optional resource solicitation study to instances where the resource acquisition is overseen by a state regulatory authority and is competitive and open. Without this requirement, NARUC is concerned about the opportunity for load-serving entities to potentially use the process in a way that would inappropriately favor the interconnection of company-owned resources."); Pine Gate Initial Comments at 43 (advocating for "appropriate safeguards"). This concern is heightened in the context where the solicitation is granted a queue position, and/or where inclusion in the solicitation serves as a commercial readiness indicator.

[42] *See, e.g.*, R Street Institute et al. June 8, 2023 Comments in Support of Generator Interconnection Reform, at 2 (urging the Commission to "[c]onsider a focused interconnection study approach"); Public Interest Organizations Initial Comments at 50-52 (highlighting the potential for a narrow study process for ERIS resources to produce significantly faster interconnection timelines); ACORE Initial Comments at 2-3 (identifying potential benefits from an interconnection process "focused on local

dilemma of unwieldy studies and cascading restudy needs, and the delay and cost uncertainty that stems from these challenges, is ultimately caused by "the interdependence amongst Interconnection Customers."[43] Cypress Creek notes that "[i]n one extreme example, a group of non-firm, energy-only resource interconnection service ('ERIS') requests triggered the need for upgrades up to 1,000 miles away on three different systems."[44] Accordingly, another way to facilitate a more workable interconnection process could be to focus study of new projects on their immediate impact to the system. While the number of studies pursuant to such a process could still be large, their scope would be smaller and the potential for cascading restudies would be greatly reduced.

23. Johannes Pfeifenberger of The Brattle Group notes that, using a "connect and manage" approach, the Electric Reliability Council of Texas (ERCOT) has interconnected more generation more quickly than other regions.[45] Under its system, which "limits restudy needs," "[p]rojects can be developed and interconnected within 2-3 years," while "in other regions, the interconnection study process itself may take longer than that."[46] Public Interest Organizations state that "[t]he UK's 'Connect and Manage' approach has reduced lead times by 5 years compared to its previous 'Invest and Connect' approach."[47]

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transmission needs only"); R Street Initial Comments at 6-7 (arguing that ERCOT's "connect and manage" approach is "perhaps the most effective" domestic interconnection process).

[43] Enel Initial Comments at 2.

[44] Cypress Creek Initial Comments at 3-4 (citing Pfeifenberger, *Generation Interconnection and Transmission Planning* (Aug. 9, 2022), https://www.esig.energy/download/generation-interconnection-and-transmission-planning-johannespfeifenberger/?wpdmdl=9241&refresh=62f38b6a0e44a1660128106).

[45] *See* Pfeifenberger, *Planning for Generation Interconnection* 2 (May 31, 2022), https://www.brattle.com/wp-content/uploads/2022/05/Planning-for-Generation-Interconnection.pdf (showing that ERCOT has interconnected more than 8 GW of capacity since 2021, significantly more than all other RTOs, even those with considerably greater peak load); *see also* Cypress Creek Initial Comments at 7.

[46] Pfeifenberger, *Planning for Generation Interconnection* at 4.

[47] Public Interest Organizations Initial Comments at 51.

24. While ERCOT's system, which treats all generators as energy-only resources,[48] may not provide a model for capacity resources, it could provide a template for ERIS interconnection. Enel argues that a "focused" approach to interconnection is appropriate for resources seeking ERIS because "the Transmission Provider is not obligated to maintain the transmission system such that ERIS generators can maintain the same level of as available injection throughout the life of the generator," and accordingly, "it would be unreasonable to expect an ERIS generator to mitigate every constraint identified" in a more expansive study that uses a lower transfer distribution factor (TDF) threshold to identify more remote impacts of the project.[49] Streamlining ERIS interconnection assessment could allow transmission providers to focus their study resources on a smaller number of requests seeking network resource interconnection service (NRIS).[50]

25. Cypress Creek argues that a more focused study approach could be implemented across the many regions that provide an NRIS interconnection option through use of a "two-step ERIS-NRIS" process by which the transmission provider could by default study all resources for ERIS and provide a subsequent process by which an interconnection customer can add firm rights.[51] Such a process might even feasibly provide a faster path to commercial operation while still facilitating deliverable resources in the long run if "NRIS requests [could] be connected more quickly on an ERIS basis while NRIS-related network upgrade study and construction work is still pending."[52] While the final rule did not adopt the recommendation for a two-step study process because it was outside the scope of this proceeding,[53] individual transmission providers could propose to implement such a process on their own initiative or the Commission could take up this suggestion in a subsequent rulemaking.

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[48] *See* Cypress Creek Initial Comments at 7-8.

[49] Enel Initial Comments at 23.

[50] *See* Public Interest Organizations Initial Comments at 50-52.

[51] Cypress Creek Initial Comments at 8-9.

[52] Public Interest Organizations Initial Comments at 52. Cypress Creek highlights that SPP currently allows for interim energy-only injection service, providing for a subsequent process by which a generator can add firm rights. Cypress Creek Initial Comments at 8-9. Such a process to add deliverability rights to ERIS resources may hold potential to facilitate immediate contributions to system reliability by these resources, even if such resources are not fully deliverable or compensated in capacity markets or accounted for in applicable resource adequacy analysis.

[53] Final Rule at P 183.

26. Key questions that this approach raises include:

a. What is the appropriate mechanism to narrow the scope of ERIS studies to limit the interdependence of projects in the study process? For example, Enel argues that ERIS resources should be studied using a minimum TDF threshold of 20 percent,[54] and that transmission providers should replace power flow models that assume extreme grid conditions with more realistic economic dispatch models reflecting security constrained economic dispatch.[55] How do these approaches interact and are they mutually exclusive? Are there other appropriate mechanisms?

b. To the extent that ERIS studies are narrowed, are changes to market dispatch rules or other measures appropriate to account for the possibility that NRIS resources or resources with long-term firm transmission service may be curtailed before them?[56]

c. If a two-step study process that considers ERIS analysis first is appropriate, how should it be designed?[57] Would it be effective to provide for a process that allows ERIS resources to be converted to NRIS after they are constructed?[58]

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[54] Enel Initial Comments at 21-25; *see also* AEE Reply Comments at 10 (supporting a minimum impact threshold); SEIA Initial Comments at 11 (same); Clean Energy Associations Initial Comments at 27 (same); Pine Gate Initial Comments at 19 (supporting a minimum distribution factor impact threshold of 20 percent).

[55] Enel Initial Comments at 73-74.

[56] Xcel objects to the treatment of ERIS resources in RTO markets because "[t]hese resources do not bear the costs necessary to ensure that they are deliverable to load as NRIS resources or ERIS resources that have acquired long term firm transmission service do," and suggests that, as a consequence, it may be appropriate for "ERIS-only service [to] receive a lower dispatch priority." Xcel Initial Comments at 15-16.

[57] Some regions currently employ a similar two-step process that considers local project needs prior to considering deliverability analysis non-local upgrades based on project interactions. *See, e.g.*, New York State Department Initial Comments at 5-6 (describing NYISO's Class Year study process).

[58] *See* Public Interest Organizations Initial Comments at 52 (arguing that "[i]deally, the interconnecting customer would receive an upfront estimate of typical curtailment levels to be expected under ERIS and would have the option to apply for NRIS at a later date if experienced curtailment levels rise above acceptable levels").

d. Could a focused interconnection approach for ERIS resources be combined with approaches above that may align the interconnection process more closely with long-term transmission planning, and/or use competitive selection processes to allocate scarce interconnection capacity?[59]

II. General interconnection process improvements

27. In addition to these deeper reforms, commenters identified several potential incremental improvements to interconnection processes that were not proposed in the Commission's notice of proposed rulemaking. I discuss some of the most promising ideas below, which in some or most cases may be applicable on a generic basis.[60]

A. Further refine study assumptions

28. Commenters identified a number of ways that study assumptions could be further clarified, which may help to streamline and improve the accuracy of the interconnection process.

1. Clarify ERIS and NRIS assumptions

29. As Enel points out, the Commission has not to date clarified what ERIS studies should entail, and it has "observed vastly different treatments of" resources seeking ERIS by different transmission providers.[61] As discussed above, a narrow approach to ERIS studies may facilitate a more streamlined interconnection process. In addition, some developers contend that grid operators deploy widely varying study assumptions on issues such as whether the models used allow for resource re-dispatch to mitigate any

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Might such a process be able to efficiently examine a large number of projects, while still requiring significantly fewer restudies than existing interconnection processes by examining only projects that have already secured ERIS?

[59] For example, might a transmission provider efficiently assess ERIS upgrades by studying them using a distribution factor of 20 percent, while simultaneously developing an "entry fee" or open season process aligned with its forward-looking transmission plan to fund upgrades to guarantee deliverability of NRIS resources?

[60] The discussion herein is not intended to comprehensively capture all potential reforms, but rather to highlight some of the ideas that may be appropriate for further stakeholder discussion.

[61] Enel Initial Comments at 26-27.

reliability issues that are identified.[62] They argue that requiring "a uniform set of minimum interconnection study requirements" would "facilitate effective, efficient interconnection queue processing."[63]

30. While the Commission declined to provide direction on how ERIS should be studied because such requests were outside the scope of this final rule,[64] the Commission could take up this topic as part of a subsequent rulemaking. As an initial step, the Commission could solicit information from transmission providers documenting what assumptions and processes are used for ERIS and NRIS, respectively, to provide a starting point for dialogue around what study assumptions may be appropriate.[65] Topics that may benefit from further clarification include: (1) the definition and scope of ERIS; (2) the study assumptions that should be implemented in examining ERIS requests; and (3) the proper scope of study results and other information that must be provided by transmission providers to interconnection customers so that they can understand the results.

2. <u>Provide for more accurate assumptions regarding injection of energy by resources</u>

31. The final rule clarifies that its requirement to more accurately reflect the proposed charging behavior of electric storage resources extends only to "the operating

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[62] *See, e.g.*, Cypress Creek Initial Comments at 6 n.11 ("Some RTOs conduct power flow analyses that consider redispatch opportunities (*e.g.*, NYISO via a manual process, PJM via a simplified approach) but many do not check if generation redispatch can address an identified criteria violation."); Pine Gate Initial Comments at 54 ("The primary issues identified relative to current study assumptions are extreme contingency scenarios and overly conservative operational characteristics and strategies (i.e., redispatch protocols).").

[63] Pine Gate Initial Comments at 55; *see also* Cypress Creek Initial Comments at 6 ("re-dispatch should be a standard approach"); Clean Energy Associations Initial Comments at 28 ("[T]he study approach to re-dispatching the system to account for proposed injections . . . is a crucial assumption that is not well understood or defined, but can trigger significant upgrades and increase complexity of interconnection process, even for energy-only (non-firm) interconnection requests. . . . Economic redispatch should be a standard approach to limit regional upgrades identified in the study process, particularly for energy-only interconnection requests.").

[64] Final Rule at P 1291.

[65] *See* Enel Initial Comments at 26-27.

assumptions for withdrawals of energy."[66] In part due to concerns regarding the administrative burden of extending the proposal to injections or other resource types, the final rule declines to extend the reform in these areas.[67] But while the Commission determined that this record did not support adopting a structure where such assumptions would be studied at the request of individual generators, further examination of how to render operating assumptions more accurate is warranted.

32. Many commenters argued that the Commission should also require more accurate assumptions regarding injections of storage.[68] And as the final rule acknowledges, many commenters "support eliminating unrealistic interconnection study assumptions for resource types other than electric storage resources, such as assuming that a solar facility will operate at night, or that a wind resource will produce maximum output during low-wind seasons."[69] Further, several commenters highlighted the benefits of using realistic fuel-based dispatch assumptions in studies, as demonstrated by MISO.[70] The final rule

[66] Final Rule at PP 1509, 1524.

[67] Final Rule at P 1529.

[68] *See, e.g.*, Clean Energy Associations Initial Comments at 53 ("[T]he Clean Energy Associations recommend that the Commission specify that transmission providers should also not study electric storage resources as 100% *injecting* energy during *low* load periods by default.") (emphasis in original); NextEra Initial Comments at 37 ("Transmission providers should not study electric storage resources as . . . injecting energy during low load and shoulder periods, as [this does] not reasonably reflect typical operations of such units."); Pine Gate Initial Comments at 51 (arguing that the Commission should prohibit transmission providers from using unrealistic operating assumptions, which includes "assuming that electric storage resources will . . . discharge during light load periods").

[69] Final Rule at P 1480 (citing Enel Initial Comments at 74; AES Clean Energy Initial Comments at 24-25; Ameren Initial Comments at 29; CREA and NewSun Initial Comments at 92; Cypress Creek Initial Comments at 9-10; Invenergy Initial Comments at 59-61; Microgrid Resources Initial Comments at 7-8; Pine Gate Initial Comments at 54; Public Interest Organizations Initial Comments at 48-49; R Street Initial Comments at 16; rPlus Initial Comments at 6); *see also id.* ("Ameren, Cypress Creek, Microgrid Resources, NARUC, Pine Gate, and rPlus all request that the Commission extend this reform to allow any resource type, not just electric storage or co-located resources, to request that interconnection studies be based on their particular operating assumptions and characteristics.").

[70] *See* Invenergy Initial Comments at 59-61 (highlighting MISO's practice, as well as "recently approved more realistic fuel-based dispatch" assumptions in SPP); *see also* Enel Initial Comments at 77-78 (arguing that the Commission should require fuel-based

"acknowledge[s] that fuel-based dispatch assumptions may be able to address some of the identified challenges associated with inaccurate modeling assumptions for all resource types and encourage[s] transmission providers to evaluate the merits of adopting it."[71] Individual transmission providers remain free to advance such assumptions on an individual basis, and further examination of this concept could create a record adequate for the Commission to determine whether to require fuel-based operating assumptions on a generic basis, and if so, how to precisely structure such a requirement.

B. Use automation to facilitate more efficient interconnection

33. Currently, the interconnection study and queue process is heavily labor-intensive, and market participants frequently suffer from shortages of qualified study staff, including transmission planners and engineers, in the face of a high volume of interconnection requests.[72] Accordingly, numerous commenters noted the great potential of automation to conserve staffing resources and speed up this process.[73] The broad term "automation" in this context can refer to a wide variety of time-saving steps to bring the

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dispatch of generators in modeling "[i]f Power flow analyses are not replaced with SCED studies"); Interwest Reply Comment at 15 (urging the adoption of "realistic fuel-based dispatch assumptions").

[71] Final Rule at P 1529.

[72] *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 176 FERC ¶ 61,207, at PP 7, 21 (2021) (noting CAISO's statement of its difficulty in finding sufficient expert staff and consultants to timely process a large cluster study); MISO, Informational Report, Docket No. ER19-1960, at 12 (filed Nov. 16, 2020) (noting similar delays); *see also* Akielly Hu, *US Clean Energy Rollout Continues to Be Hamstrung by Grid Challenges*, CANARY MEDIA (June 13, 2023), https://www.canarymedia.com/articles/transmission/us-clean-energy-rollout-continues-to-be-hamstrung-by-grid-challenges (noting that "interconnection studies rely on a workforce of engineers at grid operators, and experts say there are not enough to get the job done," and quoting the author of Lawrence Berkeley National Laboratory's *Queued Up* study as saying this staffing issue represents a "fundamental constraint" on queue processing); Avangrid Reply Comments at 12 ("Transmission providers are processing unprecedented numbers of interconnection requests at a time when these qualified transmission planners and engineers are scarce."); APPA-LPPC Initial Comments at 13 (noting that "available industry system simulation tools" can in some cases ameliorate "labor-intensive study obligations").

[73] *See, e.g.*, California Energy Storage Alliance Initial Comments at 5; NextEra Initial Comments at 14, 40; MISO Initial Comments at 26 n.107; ACORE Initial Comments at 5; ACE-NY Initial Comments at 2-3; Pine Gate Reply Comments at 5.

queue process fully into the digital age, such as standardized data entry and collection; a web-based application process and data submission with automated validation; automated study model construction and study processes; and pre-population of manufacturer models for relevant equipment.[74] Commenters requested steps, including the convening of a technical conference, to study how the interconnection process might become more robustly automated to save resources[75] and facilitate other benefits, such as the more robust integration of grid enhancing technologies (referred to as "alternative transmission technologies" in the final rule) into the bulk power system.[76] Of course, continuing to support career path development in this area will remain critical. At the same time, as we have seen in many other industries, automation done right has the potential to save a great deal of unnecessary time, effort, and expense. I support more deeply exploring the range of options available in this domain.

C. <u>Reduce delay and cost overruns in network upgrade construction</u>

34. While there appears to be a lack of good data about the timing and cost of construction of network upgrades once an interconnection agreement is executed,[77] developers have raised concerns that they have little recourse if such upgrades are delayed or subject to cost increases.[78] As noted above, the Lawrence Berkeley National Laboratory's *Queued Up* report does not trace the cause of delays between execution of a project's interconnection agreement and commercial operation, but shows that the average timespan for this period has increased from roughly 17 months for projects built between 2007-2014 to around 22 months for projects built between 2015-2022, with projects in CAISO showing particularly heightened delays.[79] Enel contends that

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[74] NextEra Initial Comments at 14, 40.

[75] *See* NextEra Initial Comments at 14; Pine Gate Reply Comments at 5.

[76] *See, e.g.*, WATT Coalition Reply Comments at 2-3.

[77] *See* Queued Up 2023 at 30 ("[L]imited data were available to analyze typical durations from interconnection agreement to commercial operations.").

[78] *See, e.g.*, Enel Initial Comments at 50 ("Under the current standard[] of . . . good utility practice, there is a notable lack of incentive, and often a disincentive, for Transmission Owners to perform . . . EPC work in a timely and cost-conscious manner."); Pine Gate Initial Comments at 64 (expressing concern that limiting the option for interconnection customers to self build will "further exacerbate construction delays and . . . ultimately harm consumers").

[79] *See* Queued Up 2023 at 30. "The typical solar project built in CAISO since 2018 took over 4 years to reach commercial operations *after securing an interconnection*

"upgrades for Interconnection Customers are only overseen by the Commission for adherence to good utility practice standards," and "[t]he Commission does not review the timeliness or cost of upgrades unless an Interconnection Customer elects to file an LGIA in unexecuted form and challenge these specific assumptions," a choice that could result in "costly delays in project timelines that often outweigh any benefit that might be gained from a favorable Commission decision."[80]

35. Accordingly, it may be appropriate for the Commission to take action to facilitate more timely and cost-conscious construction of such upgrades. One initial step could be for the Commission to gather more data concerning delays that may affect the commercial operation date of a generating facility, and to establish "metrics associated with the delayed construction of facilities."[81] The Commission could also consider adopting penalties for delays or cost overruns, or an incentive structure for transmission providers that carry out construction on time and on budget.[82]

36. Finally, it may be appropriate to reconsider the scope of "stand alone network upgrades" to include facilities that may be needed for multiple interconnection customers, and to develop a process that either designates an interconnection customer to build such upgrades, or competitively solicits bids to award construction rights. While this final rule "clarif[ies] that, for a network upgrade to be eligible for treatment as a stand alone network upgrade, the network upgrade must be required for only one interconnection

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agreement; those built in 2022 averaged over 6 years." *Id.* (emphasis in original).

[80] Enel Initial Comments at 50-51.

[81] Pine Gate Initial Comments at 64.

[82] This issue has also arisen in the context of the Commission's docket on transmission planning and cost management. *See, e.g.*, Advanced Energy Economy, Pre-Conference Comments, Docket No. AD22-8, at 2-3 (filed Oct. 4, 2022) (noting that a "major driver[] of transmission cost increases in recent years [has] been . . . incremental network upgrades identified in generator interconnection studies"). In that docket, the Commission has considered, and some commenters have supported, among other measures, new independent entities to monitor transmission planning. *See, e.g.*, Electricity Transmission Competition Coalition, Comments, Docket No. AD22-8, at 6 (filed Oct. 4, 2022); Harvard Electricity Law Initiative, Comment, Docket No. AD22-8, at 18-31 (filed Mar. 23, 2023); R Street Institute, Comments, Docket No. AD22-8, at 6-7 (filed Mar. 23, 2023). To the extent that such entities are established, the Commission could also consider tasking them with monitoring the timely and cost-conscious construction of network upgrades.

customer,"[83] it does so in order to "explicitly maintain[] the status quo."[84] The Commission's Notice of Proposed Rulemaking examined changes to the definition of stand alone network upgrade necessary "to implement a first-ready, first-served cluster study process,"[85] and did not contemplate any mechanism to "prevent lengthy conflict and negotiations in instances where multiple interconnection requests trigger the need for a network upgrade" beyond restricting such upgrades to those that are required for only one interconnection customer.[86]

37. Ideas were put forth in this proceeding, however, that may hold potential to efficiently allocate construction rights and obligations. In particular, one idea is that "the Commission should consider establishing a new third-party construction option" pursuant to which stand alone network upgrades could "be bid out and built by third parties, such as non-incumbent utilities, independent transmission developers or contractors."[87] To develop such an option, the Commission would need to consider "details such as the posting of minimum design standards that must be met, the criteria for choosing a winning bidder, the incentives to hold the winning bidder to cost and schedule estimates, responsibility for cost overruns, rights to own, operate and maintain the Stand-Alone Network Upgrades, and the profit awarded to the winning bidder."[88] Further process is warranted to examine this concept.[89] I encourage transmission providers to work with

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[83] Final Rule at P 192.

[84] *Id.* at P 193.

[85] *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194, at P 65 (2022).

[86] *Id.*; *see* Final Rule at P 194 (requests to "expand the definition of stand alone network upgrade . . . are outside the scope of this proceeding, which is not proposing to modify the scope of interconnection customers' option to build certain stand alone network upgrades but rather is only revising definitions insofar as is necessary to implement reforms adopted elsewhere in this final rule").

[87] Enel Initial Comments at 52; *see also* Pine Gate Initial Comments at 63-64 (proposing that "the Commission should grant the interconnection customer with the largest projected impact on a potential Stand Alone Network Upgrade facility the ability to elect the option to build with priority falling to each interconnection customer based on their interconnection request having the next largest impact on the Stand Alone Network Upgrade").

[88] Enel Initial Comments at 52.

[89] Enel notes that "[t]he Commission could establish workshops or other

interconnection customers and other stakeholders to explore structures such as this that may provide greater certainty surrounding the timing and cost of certain network upgrades.

D. <u>Address challenges faced by projects serving Tribes and Tribal communities</u>

38. Beyond these recommendations to further facilitate efficient interconnection of new resources, I encourage transmission providers to examine potential changes to address important considerations of equity and fairness related to interconnection of resources serving or developed by Tribes. In particular, I encourage transmission providers to examine whether any exceptions or waivers to the commercial readiness requirements or withdrawal penalties framework are appropriate for certain projects serving Tribal nations or their communities. While the commercial readiness deposit and withdrawal framework adopted in this final rule hold the potential to make interconnection processes more efficient, they may act as a barrier to projects serving or developed by Tribes in cases where such projects adopt unique ownership and financing structures.[90] This may also be a concern with regard to projects developed by, or in partnership with, communities that have been historically marginalized or overburdened by pollution, and I encourage further dialogue examining whether that is the case.

39. For example, the Commission recently granted a waiver to the SAGE Development Authority (SAGE), an entity developing a wind generation project on Tribal land, to allow it more time to post financial security as required by SPP.[91] SAGE was created by the Standing Rock Sioux Tribe and is developing the project through "a community-led process designed to, among other things, implement Tribal values and ensure that the financial benefits of the Project will in turn support further community projects intended to address disparities around public health and other issues."[92] The Commission granted SAGE's requested waiver in part because "due to its unique Tribal business structure, it [was] unable to secure credit in advance" of the relevant security

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mechanisms to further explore and develop these details." *Id.*

[90] *See* OSPA Initial Comments at 8, 15-16 (arguing that SPP's current security deposit regime has been "an insuperable barrier to renewable energy development on Tribal lands").

[91] *See SAGE Development Authority*, 182 FERC ¶ 61,180 (2023).

[92] *Id.* at P 4.

deposit deadline.[93] Waiver "provide[d] SAGE the time necessary to secure additional credit."[94]

40. To the extent this rule's deposit requirements subject Tribal projects to greater risk, the need for similar waivers could be heightened. Accordingly, I encourage further inquiry into whether certain projects developed to serve Tribal communities or disadvantaged communities may have other characteristics that uniquely demonstrate commercial readiness as alternatives to the new deposit requirements. The inquiry could also consider other measures that may allow such projects to overcome any unique barriers that they face.[95]

41. While challenges remain, the Commission's issuance of a final rule today is an important step forward in the effort to address interconnection backlogs around the country. The ideas for continuing reform that I describe in this concurrence represent best practices and innovative thinking by regions and stakeholders considering how to solve the challenges the final rule does not address. I encourage transmission providers, interconnection customers and other stakeholders to consider the rule's requirements a strong baseline and not a ceiling, and to continue to engage on the topics I have addressed herein.

For these reasons, I respectfully concur.

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Allison Clements
Commissioner

[93] *Id.* at P 20.

[94] *Id.*

[95] *See also* Energy Keepers Initial Comments at 2-3 (arguing that it would not be "unduly discriminatory or preferential for transmission providers to expedite the processing of Native American interconnection requests," considering "prior environmental justice inequities.").

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements Docket No. RM22-14-000

(Issued July 28, 2023)

CHRISTIE, Commissioner, *concurring*:

1. I concur to this final rule,[1] which represents major progress towards the primary goal we set out to accomplish last year when we issued the NOPR: To move from a system of "first come, first served" to a system of "first ready, first served" by identifying generation projects in the interconnection queues that are commercially more viable and then moving them ahead of requests that are speculative and which have been causing major backlogs. I write separately about four issues contained within:

I. Evaluation of Alternative Transmission Technologies (Section III.C.2.iii)

2. Alternative transmission technologies, or grid-enhancing technologies (GETs), is a short-hand categorical term that covers a sweeping array of very different technologies. A GET may hold the potential of squeezing more juice – literally – out of the existing transmission grid. By increasing the capacity of the existing grid, a GET could reduce or even eliminate the need for the future construction of new transmission assets. So the potential for cost-savings from the use of GETs is too important to ignore.

3. One of the most promising GETs – dynamic line ratings (DLRs) – could potentially save billions of dollars in avoided costs for new transmission assets. DLRs are not covered by this final rule, but are the subject of a separate proceeding,[2] and I hope we will use the record of that proceeding to move forward on a proposed rule to require implementation of DLRs when and where DLRs will be technologically sound and cost-effective.

4. While DLRs have tremendous potential and should be pursued, there is a problem with any categorical regulatory mandate to use GETs, which is this: Some GETs work somewhere but not everywhere; some work sometimes but not all the time; some only work under certain weather conditions; some don't work at all, or at least not as

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[1] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023) (Final Rule).

[2] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (2022).

advertised; and some are only cost-effective where the congestion costs are greater than the cost of the GET itself.

5. Given these engineering and economic realities, some knowledgeable transmission planning experts have argued that GETs categorically are not planning tools, but rather are *operational* applications that should be deployed when and where their efficacy is likely and can be appropriately proven. If they work in the real world as advertised, they could reduce or eliminate the need for *future* network upgrades or even backbone transmission assets, but they should not be mandated as planning tools or as potential substitutes for network upgrades caused by interconnection requests.[3]

6. Against this cautious view of GETs, I recognize the counterargument that transmission *owners* themselves have an economic incentive to favor the construction of costly new transmission assets rather than deploy GETs to squeeze out more capacity. New transmission assets can be rate-based, and the transmission owner can take advantage of the very generous formula rate treatment offered here at the Commission (another issue I have raised concerns about).[4] So to overcome this incentive against GETs deployment, proponents argue that the Commission should require it.

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[3] *See* PJM Initial Comments at 68 ("PJM therefore cautions the Commission *not* to conflate the *operational* benefits of alternative transmission technologies . . . with the need to address significant capacity enhancement needs (short and long-term) or long-range transmission needs under rapid growth or changing resource mix scenarios."); MISO Initial Comments at 121-22 ("Further, although these technologies may be evaluated, the technologies identified by the Commission still may *not* provide the appropriate solution from a *planning* perspective. Many of the technologies identified are appropriately considered as *operational tools or short-term solutions* but are *not* necessarily appropriate for *planning* to support a particular generator interconnection.") (emphases added, footnote omitted).

[4] *See, e.g.*, *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,151 (2023) (Clements, Comm'r, and Christie, Comm'r, concurring at P 4) ("Indeed, the Commission grants formula rate treatment, including a presumption of prudence, to filings from transmission owners seeking cost recovery for transmission projects without regard to whether such projects have been subject to a serious vetting in any proceeding in which both need and prudence of cost must be demonstrated by the transmission developer. We have expressed concerns about this lack of oversight previously, and this filing by SPP illustrates exactly why that is a major problem pertinent to the issue of rising consumer costs for transmission."), https://www.ferc.gov/news-events/news/commissioner-clements-and-commissioner-christies-joint-concurrence-spp-project; Transmission Planning and Cost Management, Technical Conference, Docket No. AD22-8-000, Tr. 16:4-20:11 (Comm'r Mark Christie) (Oct. 6, 2022).

7. But – as usual – the economic incentives argument has more than one side. The companies that sell GETs (and the organizations they fund) stand to profit from any regulation mandating that their products must be used. And generation developers (and the organizations they fund) have every incentive to lobby for a regulation mandating the use of GETS as a way to avoid paying the costs of the traditional network upgrades made necessary by their interconnections. This incentive is particularly salient in RTOs/ISOs that use participant funding to pay for the costs of network upgrades caused by the interconnecting customers (i.e., developers).

8. So – again, as usual with sweeping Commission regulations – there is plenty of rent-seeking to go around. Striking the appropriate balance – one that is in the *public* interest – is a challenge. I believe this final rule – unlike the NOPR – does strike the right balance, in terms of a requirement simply to evaluate GETs in determining the appropriate network upgrade.

9. Importantly, the final rule makes it explicitly clear that while it is requiring the *evaluation* of certain listed GETs in the interconnection studies process, it is *not* requiring – nor even suggesting – that a GET must be deployed as an alternative to a necessary network upgrade. Indeed, the final rule explicitly says:

> This final rule does not create a presumption in favor of substituting alternative transmission technologies for necessary traditional network upgrades, either categorically or in specific cases. This final rule is agnostic as to whether, in a specific case, an alternative transmission technology is an acceptable alternative to a traditional network upgrade . . . .

10. The final rule also makes it explicitly clear that the determination in each case is to be made at the *sole* discretion of the transmission provider (i.e., RTO/ISOs or non-RTO transmission providers), applying good utility practices, applicable reliability standards, and other applicable regulatory requirements. To avoid continual litigation aimed at the transmission provider's determination in specific cases when a generation developer does not want to pay the costs of a network upgrade, the final rule explicitly makes clear that it is requiring a *process* of evaluation, *not mandating outcomes* in specific cases. And it makes clear that if the transmission provider performs the *evaluation* as required in the final rule, it has complied with the final rule.

11. This agnosticism as to outcomes in specific cases is critically important. Transmission providers must require the appropriate network upgrade necessary to fix the reliability issue caused by the interconnection request. If a GET is used instead, and it fails to fix the reliability issue caused by the interconnection, a later network upgrade will be required, one potentially more costly than the network upgrade originally required. And who will pay those costs? Certainly in RTOs/ISOs using participant funding, *load*

(retail consumers) should not. Sticking those costs on consumers would raise a serious question of unjust and unreasonable rates.

12. In summary though, I believe that this final rule strikes the appropriate balance between requiring the evaluation of GETs, but not mandating the use of a GET in specific cases unless the transmission provider – and only the transmission provider – determines it would work from a real-world applicability standpoint. In all cases, the transmission provider should apply its engineering expertise to come to the right determination as to the necessary network upgrades. This final rule requires nothing less.

II. Repayment of Affected Systems Network Upgrade Costs (Section III.B.2.c.iii(c))

13. The final rule essentially codifies existing precedent as to the repayment of affected systems network upgrade costs when a generation developer interconnects at or near a seam between an RTO (which uses participant funding to pay for interconnection costs) and a non-RTO, vertically integrated load-serving utility that uses a crediting mechanism.

14. Three recent cases involving Duke Energy Progress, LLC (Duke) in North Carolina[5] illustrate my concern about the Commission's repayment policy.[6] In these cases, generation developers located within the PJM footprint, which extends into a corner of northeastern North Carolina due to Dominion Energy, Inc.'s PJM membership,

[5] *Duke Energy Progress, LLC*, 181 FERC ¶ 61,229 (2022), *reh'g deemed denied*, 182 FERC ¶ 62,088 (2023); *Duke Energy Progress, LLC*, 180 FERC ¶ 61,005, *order on reh'g*, 181 FERC ¶ 61,197 (2022) (Edgecombe Rehearing Order); *Duke Energy Progress, LLC*, 177 FERC ¶ 61,001 (2021), *order on reh'g*, 179 FERC ¶ 61,007 (2022) (American Beech Rehearing Order). My concurrences to the Edgecombe Rehearing Order and American Beech Rehearing Order set forth my concerns as well. *See* Edgecombe Rehearing Order, 181 FERC ¶ 61,197 (Christie, Comm'r, concurring) (Edgecombe Concurrence), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-rehearing-duke-energy-progress; American Beech Rehearing Order, 179 FERC ¶ 61,007 (Christie, Comm'r, concurring).

[6] *See Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at PP 693-696, 720-739 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932, 106 FERC ¶ 61,220, at PP 584-586, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 19, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (July 18, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007). I note that this policy applies not just to affected systems network upgrades but also network upgrades on the host transmission provider's system.

chose to interconnect very close to the seam with Duke's North Carolina territory. Duke is a vertically integrated utility regulated by the North Carolina Utilities Commission (NCUC) on an Integrated Resource Plan (IRP) model. Duke builds transmission (and generation) subject to an IRP approved by the NCUC, and the costs of network upgrades caused by that new generation are paid by retail consumers. Since the NCUC approves new generation through its IRP process, which includes the costs to interconnect that new generation, the NCUC decides the generation and interconnection costs that are appropriately paid for by retail consumers.

15. In these three cases, however, Duke was considered an "affected system" for the interconnection costs caused by the generation developers located just across the seam in PJM's footprint. So the affected systems network upgrades were not paid by the developer (creating an incentive to locate close to the seam), but by Duke's retail consumers through crediting pursuant to Commission policy. And unlike the costs of transmission and network upgrades built with the prior approval of the NCUC, no state-approved IRP controls the construction of generation in the PJM footprint in North Carolina. Not surprisingly, the NCUC and the NCUC Public Staff, which represents consumers in North Carolina, filed vigorous – and in my opinion, persuasive – comments in several proceedings on these issues.[7]

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[7] *See* NCUC and NCUC Public Staff Initial Comments at 6; NCUC and NCUC Public Staff, Joint Comments, Docket No. RM21-17-000, at 12 (filed Aug. 17, 2022); NCUC Public Staff, Comments, Docket No. RM21-17-000, at 13-15 (filed Oct. 12, 2021); NCUC Public Staff Reply Comments, Docket No. RM21-17-000, at 6 (filed Nov. 30, 2021) ("[U]nder the crediting policy, ratepayers are left paying the bill regardless of the benefits, or lack thereof, they received from the network upgrades. Further, the [NCUC] Public Staff believes that [interconnection customers] are beginning to 'game' the system by placing large merchant plants into the interconnection queue in congested areas to take advantage of the crediting policy and fill what excess capacity is then created with state jurisdictional projects that would normally have to fund the upgrades themselves."); *see also* NCUC Public Staff, Motion to Intervene Out-of-Time and Comment, Docket No. ER21-1955-003, at 1-9 (filed Nov. 9, 2021) (generally arguing, *inter alia*, that Duke customers will not or will only minimally benefit from upgrading its system to accommodate power being interconnected and delivering to PJM; that Duke ratepayers are subsidizing costs that should be paid for by the developer, the party that is both causing the costs to be incurred and reaping the resulting benefits; that given the proliferation of merchant generation trying to locate in this area of North Carolina, the NCUC Public Staff is concerned that Duke ratepayers will be burdened with potentially hundreds of millions of dollars in affected systems network upgrade cost as a result of the Commission's actions; and that the project in American Beech had not yet received a CPCN from North Carolina so any decision put the "cart before the horse.").

16. While I recognize that the results in these cases were consistent with prior precedent and Order No. 2003,[8] I think that precedent and, if necessary, Order No. 2003 itself, should be revisited as to the affected systems repayment policy. I concur to the issuance of this final rule because this final rule is not the appropriate place to revisit the issue and because the final rule by its own terms does not go beyond existing precedent.

III. <u>Inappropriate Allocation of Certain Costs to Consumers</u>

17. As described below, while I support the final rule, I am concerned that study delay penalties on RTOs/ISOs and the costs of transmission provider heatmaps used as a tool for interconnection customers will be inappropriately allocated to consumers even though they both appear to provide much more of a benefit to generation developers than consumers. I address each in turn.

A. <u>Study Delay Penalties on RTO/ISOs (Section III.B.1.c.x)</u>

18. The final rule adopts the NOPR proposal to eliminate the reasonable efforts standard from the *pro forma* LGIP, and it adds a new section to the *pro forma* LGIP that imposes penalties on transmission providers who miss study deadlines. I have no qualms about assessing penalties on non-RTO/ISO transmission providers and transmission-owning members of RTOs/ISOs. These are generally investor-owned companies and stockholders will bear such costs. On the other hand, I have concerns about assessing study penalties on RTOs/ISOs, as they are not-for-profit entities who do not have stockholders. In my concurrence to the NOPR, I explained:

> [T]he penalty provisions do not answer definitively the most important question of all: Who will pay these penalties in an RTO or ISO which has no stockholders? Consumers certainly should not pay, directly or indirectly.[9]

The final rule does not fully address this question and does not provide complete assurance that consumers will be protected.

19. However, the final rule does have some protections in place to protect against consumers ultimately having to pay for study delay penalties. First, the final rule modifies the NOPR proposal to prohibit non-RTO/ISO transmission providers and

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[8] *See, e.g.*, Edgecombe Concurrence.

[9] *Improvements to Generator Interconnection Procs. & Agreements*, 87 FR 39934 (July 5, 2022), 179 FERC ¶ 61,194 (2022) (Christie, Comm'r, concurring at P 3) (NOPR Concurrence), https://www.ferc.gov/news-events/news/e-1-commissioner-christies-concurrence-improvements-generator-interconnection.

transmission-owning members of RTOs/ISOs from recovering study delay penalty amounts through transmission rates.[10] Second, the final rule modifies the NOPR proposal to adopt a new provision in our regulations specifying that, for RTOs/ISOs in which the transmission-owning members perform certain interconnection studies, the study delay penalties will automatically be imposed directly on the transmission-owning member(s) that conducted the late study.

20. But these provisions still leave open the question of how RTOs/ISOs will recover those study delay penalties that are not automatically imposed on a transmission-owning member. The final rule essentially punts on this question, explaining that RTOs/ISOs may submit an FPA section 205 filing to propose a default structure for recovering study delay penalties and/or make individual FPA section 205 filings to recover the costs of any specific study delay penalties. I urge that any such RTO/ISO filing make protections to consumers paramount.

B. Cost of Heatmap (Section III.A.1.c.iii)

21. This final rule requires transmission providers to publicly post a "heatmap" with certain information after the completion of each cluster study and cluster restudy period. The final rule finds that the heatmap will benefit *interconnection customers*, including prospective interconnection customers, by providing them further transparency as to expected congestion and potential network upgrades and therefore will reduce the number of speculative interconnection requests. I agree that a requirement to post a heatmap will greatly benefit interconnection customers and support the requirement's addition to the *pro forma* LGIP.

22. Where I am concerned, however, is how the heatmap should be funded. The final rule clarifies that transmission providers, *not* interconnection customers, are responsible for paying the costs associated with the heatmap requirement. Further, the final rule contemplates transmission providers recovering the costs of the heatmap from transmission customers and *ex ante* determines that such rate treatment is appropriate because interconnection queue efficiency benefits transmission customers. Commission policy may dictate that interconnection queue efficiency benefits transmission customers;[11] however, that should not result in the costs of a requirement that best benefits interconnection customers, and really *prospective* interconnection customers that may ultimately not seek to interconnect, being recovered from *consumers* through transmission rates *carte blanche*. The Commission simply cannot ask retail consumers to foot the bill for every single "efficiency," especially where many of these "efficiencies"

[10] Final Rule, Section III.B.1.c.ix.

[11] Whether or not I agree with Commission policy is another matter entirely. *See, e.g.*, *supra* PP 13-16.

largely benefit generation developers and then get folded into transmission rates and receive an ROE.[12]

23. I believe this issue merits further scrutiny, and I look forward to future comments on this issue.

IV. <u>"Hold Harmless" Provisions (Sections I, III.A.6.c.iii, IV.C)</u>

24. In my concurrence to the NOPR, I wrote that while I supported the proposed queue reforms (subject, of course, to comment):

> I also caution strongly that we should avoid undermining through this NOPR what the RTOs/ISOs, working through their stakeholder processes, are already doing to fix their own queue problems. We should recognize that each RTO/ISO is different and faces unique local challenges and needs. The queue reforms proposed in today's NOPR should be seen more as guideposts or general standards rather than unyielding mandates that refuse to take local solutions into consideration. *I would allow RTOs/ISOs the opportunity to demonstrate that if their own efforts to enact queue reforms achieve the same goals in a different, but equally effective manner, their individual reform may be acceptable in complying with any final rule.* While this NOPR currently recognizes the potential for regional flexibility, I hope the need for such flexibility is explicitly memorialized in any final rule.[13]

25. This final rule contains language that is intended to recognize the earnest and good-faith efforts undertaken by the RTOs to enact queue reforms. Some RTOs, such as

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[12] Joint Fed.-State Task Force on Elec. Transmission, Technical Conference, Docket No. AD21-15-000, Tr. 37:9-20 (Comm'r Mark Christie) (Nov. 15, 2022) ("Let's put this in context, and talk about what's really at stake here. Last year national transmission rate base went up over 9 percent. That's the third consecutive year it's gone up over 9 percent. What goes into rate base, goes into consumer's bills. Every nickel. And in the last decade, national transmission rate base has almost tripled, and . . . at 9 percent it's going to double again in the next eight years. This is all going into customer's bills. So this is a hugely important issue. This is a ton of money, this is big, big money.").

[13] NOPR Concurrence at P 4 (emphasis added, footnote omitted).

PJM, have already launched extensive queue reforms; others, such as CAISO, are hard at work on developing queue reforms.

26. I concur because this final rule does contain language that is at least intended to recognize the efforts of RTOs to act on their own queue reforms without waiting on a Commission rulemaking. Whether the language of this final rule adequately recognizes or "holds harmless" those efforts will be an issue for compliance filings.

For these reasons, I concur.

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Mark C. Christie
Commissioner

Document Content(s)

Exhibit B

Improvements to Generator Interconnection

Procedures and Agreements

Notice of Denial of Rehearing by Operation of Law

and Providing for Further Consideration

Docket No. RM22-14-001

184 FERC ¶ 62,163 (2023)

(Sept. 28, 2023)

184 FERC ¶ 62,163
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements | Docket No. RM22-14-001

NOTICE OF DENIAL OF REHEARING BY OPERATION OF LAW AND PROVIDING FOR FURTHER CONSIDERATION

(September 28, 2023)

Rehearing has been timely requested of the Commission's order issued on July 28, 2023, in this proceeding. *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (2023). In the absence of Commission action on a request for rehearing within 30 days from the date it is filed, the request for rehearing may be deemed to have been denied. 16 U.S.C. § 825*l*(a); 18 C.F.R. § 385.713 (2022); *Allegheny Def. Project v. FERC*, 964 F.3d 1 (D.C. Cir. 2020) (en banc).

As provided in 16 U.S.C. § 825*l*(a), the requests for rehearing of the above-cited order filed in this proceeding will be addressed in a future order to be issued consistent with the requirements of such section. As also provided in 16 U.S.C. § 825*l*(a), the Commission may modify or set aside its above-cited order, in whole or in part, in such manner as it shall deem proper.

Kimberly D. Bose,
Secretary.

Document Content(s)

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